Message

From: Hambrick, Amy [Hambrick.Amy@epa.gov]
Sent: 6/21/2018 8:11:09 PM
To: Whiteman, Chad S. EOP/OMB [Chad_S_Whiteman@ Ex. 6 Personal Privacy (PP)
CC: Cozzie, David [Cozzie.David@epa.gov]; Fruh, Steve [Fruh.Steve@epa.gov]; Hambrick, Amy [Hambrick.Amy@epa.gov]
Subject: RE: EO 12866 Comments on EPA Oil and Gas Reconsideration NPRM 2060-AT54
Attachments: EO12866_Oil and Gas Reconsideration Proposal RIA 2060-AT54 _20180620_CLE....docx; EO12866_Oil and Gas Reconsideration Proposal RIA 2060-AT54 _20180620_RLS....docx; EO12866_2nd.Supplemental Response to Comments_Oil and Gas Reconsideratio....docx; State Fugitives Memo for OOOOa Reconsideration_CLEAN 6.21.2018.docx; State Fugitives Memo for OOOOa Reconsideration_RLSO 6.21.2018.docx; Updated 062118 Proposed Rule OOOOa TSD Section 2 - M21 Well Pad Model Pl....xlsx; Updated 062118 Proposed Rule OOOOa TSD Section 2 - OGI Well Pad Model Pl....xlsx; EO12866_Oil and Gas Reconsideration Proposal 2060-AT54 TSD 20180621_CLEA....docx; EO12866_Oil and Gas Reconsideration Proposal 2060-AT54 TSD 20180621_RLSO....docx; EO12866_Oil and Gas Reconsideration Proposal 2060-AT54 NPRM 20180621_RLS....docx; EO12866_Oil and Gas Reconsideration Proposal 2060-AT54 NPRM 20180621_CLE....docx

HI Chad,

This email contains the following 11 attachments:

(1) Supplemental response to the second round of EO 12866 interagency comments (1 attachment)
(2) RIA (2 attachments: RLSO and clean)
(3) State Equivalency Memo: This was updated to reflect the recent Pennsylvania updates. (2 attachments: RLSO and clean)
(4) TSD (4 attachments: RLSO and clean and those spreadsheets that were updated)
(5) Preamble (2 attachments: RLSO and clean)

Thank you,

Amy

Amy Hambrick
U.S. Environmental Protection Agency
(919)541-0964

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

Background:

- On June 8, 2018, the Interstate Natural Gas Association of America (INGAA) submitted a white paper to OMB and EPA titled "Methane Emissions from Natural Gas Transmission and Storage Facilities: Review of Available Data on Leak Emission Estimates and Mitigation Using Leak Detection and Repair" ("INGAA White Paper").
- Below is EPA's analysis of the information included in the INGAA White Paper.

Canadian Association of Petroleum Producers (CAPP):

- The CAPP 2014 report titled "Update of Fugitive Equipment Leak Emission Factors" was referenced in the INGAA White Paper as concluding that an annual monitoring frequency resulted in 75-80% emission reductions since the 2007 CAPP Best Management Practices for fugitive emissions were implemented.
- EPA has previously provided a response to Interagency Reviewers regarding this study. EPA's analysis of the 2014 CAPP report is provided here for completeness of the evaluation of the INGAA White Paper.
- As noted in our earlier response, the 2014 CAPP study was conducted to determine if updates were needed for the emissions factors that were developed using data collected from the mid-1990s to early 2000s. In 2007, CAPP issued Best Management Practices for fugitive emissions at oil and gas sites. These BMPs did not specify a leak definition, monitoring frequency, repair timeline, or the components to monitor. Instead, it provided an outline of suggestions to help a facility design a program to target finding and fixing leaks from equipment more likely to leak. In 2014, CAPP evaluated the information submitted from a few companies to determine if the emissions factors should be updated and concluded there was a net component-weighted reduction of 75% of the emissions across all component categories. This is not reflective of a 75% reduction in emissions from an annual fugitive emissions monitoring program, as suggested in the interagency review. There were no established monitoring requirements specified by the 2007 CAPP BMPs, therefore, the EPA is not able to conclude any details about the specific monitoring programs implemented at the facilities that resulted in the component-weighted 75% reduction of emissions across all component categories. Additionally, the comparison of the emissions factors does not appear appropriate because only 1 facility provided actual leak measurements for the 2014 study, with all other data based on estimated component counts and leak/no-leak factors.

Pipeline Research Council International (PRCI) as summarized by INGAA White Paper:

- The PRCI 2018 report titled "GHG Emission Factor Development for Natural Gas Compressors" was referenced in the INGAA White Paper as providing calculated emissions factors for compressors from direct measurements of major compressor components as part of Greenhouse Gas Reporting Program (GHGRP) Subpart W reporting for the years 2011 through 2016. (Note: EPA was not provided with a copy of the PRCI report.) The INGAA White Paper compared the subpart W reported compressor source emissions to subpart W reported equipment leak emissions to suggest that fugitive emission sources are "relatively minor" compared to compressor emissions. The INGAA White Paper also provided a summary of the number of equipment leaks identified for non-compressor and compressor components at transmission and storage stations as reported to Subpart W for the years 2011-2016.
- Under GHGRP Subpart W, vented and fugitive emissions from compressors may be reported under the centrifugal compressor venting emission source, reciprocating compressor venting emission source, or equipment leaks emission source.

- Devices that vent under the normal course of operations are not fugitive emissions components for purposes of NSPS OOOOa. For example, wet seal oil degassing vents from centrifugal compressors *would not* be considered fugitive emissions components under NSPS OOOOa.
- Conversely, there are some emission sources that are reported under the Subpart W centrifugal compressor venting emission source or the Subpart W reciprocating compressor venting emission source that *would* be considered fugitive emissions components under NSPS OOOOa; for example, isolation valve leakage and blowdown valve leakage that is not part of normal operations from centrifugal or reciprocating compressors.
- Subpart W data reported as "equipment leaks" for compressors cannot be directly compared to "fugitive emissions components" under NSPS OOOOa because of differences in how the emissions are characterized and counted.

California Air Resources Board (CARB):

- The CARB 2016 report titled "Enhanced Inspection & Maintenance for GHG & VOCs at Upstream Facilities – Final (Revised)" was referenced in the INGAA White Paper as providing average gas leak rates for various EPA Method 21 screening values.
- The CARB study included a data set of 160 components at 39 sites. Of these 160 components, only 7 were located at natural gas compressor and transmission sites. The remaining components were located at well sites, production facilities, water separation facilities, and natural gas processing plants.
- NSPS OOOOa requires the use of OGI for monitoring for fugitives because EPA concluded that OGI is BSER. Method 21 is allowed as an alternative to OGI but decisions regarding the emissions and costs of the requirements are made based on OGI monitoring, not Method 21. It is not possible to apply the correlation equations presented in the White Paper to the emission estimates for OGI because OGI does not provide a screening value. Further, EPA believes the conclusions presented in the White Paper regarding potentially "extremely low" emissions from gas leaks at 500 ppm using Method 21 are not appropriately extrapolated from the study. As stated in the CARB study and the White Paper, this study was limited in scope, the measurements were not collected for the development of emission factors, the correlation equations do not account for large sources of emissions (e.g., super-emitters), and that additional leaks identified during the study were discarded once a matrix was completed.
- The CARB study focused on using a variety of emission measurement technologies to develop correlation equations from a limited set of observations, which did not address national representativeness or leak frequency as used in the conclusions of INGAA's white paper.

6560-50-P

40 CFR Part 60

[EPA-HQ-OAR-2017-0483; FRL-XXXX-XX-OAR]

RIN 2060-AT54

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed Rule.

SUMMARY: This action proposes reconsideration amendments to the new source performance standards (NSPS) at 40 Code of Federal Regulations (CFR) part 60, subpart OOOOa, (2016 NSPS OOOOa). The Environmental Protection Agency (EPA) received petitions for reconsideration on the 2016 NSPS OOOOa. The EPA granted reconsideration on three issues: (1) fugitive emissions requirements, (2) well site pneumatic pump standards, and (3) the requirements for certification of closed vent systems by a professional engineer based on specific objections to these requirements. This action proposes amendments and clarifications as a result of reconsideration of these issues. The proposed amendments also address other issues raised for reconsideration and make technical corrections and amendments to further clarify the rule.

DATES: *Comments.* Comments must be received on or before **[INSERT DATE 45 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your

comments on or before **[INSERT DATE 45 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

Public Hearing. If a public hearing is requested by **[INSERT DATE 5 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, then we will hold a public hearing on **[INSERT DATE 15 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]** at the location described in the **ADDRESSES** section. The last day to pre-register in advance to speak at the public hearing will be **[INSERT DATE 13 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA-HQ-OAR-2017-0483, at *http://www.regulations.gov*. Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from Regulations.gov. (See SUPPLEMENTARY INFORMATION for detail about how EPA treats submitted comments.) Regulations.gov is our preferred method of receiving comments. However, other submission methods are accepted:

- *Email:* a-and-r-docket@epa.gov. Include Docket ID No. EPA-HQ-OAR-2017-0483 in the subject line of the message.
- *Fax:* (202) 566-9744. Attention Docket ID No. EPA-HQ-OAR-2017-0483.
- *Mail:* To ship or send mail via the United States Postal Service, use the following address: U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA-HQ-OAR-2017-0483, Mail Code 28221T, 1200 Pennsylvania Avenue, NW, Washington, DC 20460.
- *Hand/Courier Delivery:* Use the following Docket Center address if you are using express mail, commercial delivery, hand delivery, or courier: EPA Docket Center, EPA

WJC West Building, Room 3334, 1301 Constitution Avenue, NW, Washington, DC 20004. Delivery verification signatures will be available only during regular business hours.

Public Hearing. If a public hearing is requested, it will be held at {***INSERT LOCATION}. If a public hearing is requested, then we will provide details about the public hearing on our Web site at: *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/actions-and-notices-about-oil-and-natural-gas*. The EPA does not intend to publish another document in the Federal Register announcing any updates on the request for a public hearing. Please contact Aimee St. Clair at (919) 541-1063 or by email at stclair.aimee@epa.gov to request a public hearing, to register to speak at the public hearing, or to inquire as to whether a public hearing will be held. See **SUPPLEMENTARY INFORMATION** for instructions on registering and attending a public hearing.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Ms. Amy Hambrick, 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) 541-0964; fax number: (919) 541-3470; and email address: hambrick.amy@epa.gov. For information about the applicability of the new source performance standard (NSPS) to a particular entity, contact Ms. Marcia Mia, Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, EPA WJC South Building (Mail Code 2227A), 1200 Pennsylvania Avenue, NW, Washington DC 20460; telephone number: (202) 564–7042; and email address: mia.marcia@epa.gov.

SUPPLEMENTARY INFORMATION:

Public hearing. The EPA will make every effort to accommodate all speakers who arrive and register. If a hearing is held at a U.S. government facility, individuals planning to attend should be prepared to show a current, valid state- or federal-approved picture identification to the security staff to gain access to the meeting room. An expired form of identification will not be permitted. Please note that the Real ID Act, passed by Congress in 2005, established new requirements for entering federal facilities. If your driver's license is issued by a noncompliant state, you must present an additional form of identification to enter a federal facility. Acceptable alternative forms of identification include: Federal employee badge, passports, enhanced driver's licenses, and military identification cards. Additional information on the Real ID Act is available at https://www.dhs.gov/real-id-frequently-asked-questions. In addition, you will need to obtain a property pass for any personal belongings you bring with you. Upon leaving the building, you will be required to return this property pass to the security desk. No large signs will be allowed in the building, cameras may only be used outside of the building, and demonstrations will not be allowed on federal property for security reasons.

Docket. The EPA has established a docket for this rulemaking under Docket ID No. EPA-HQ-OAR-2017-0483. All documents in the docket are listed in the Regulations.gov index. Although listed in the index, some information is not publicly available, *e.g.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically in Regulations.gov or in hard copy at the EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Avenue, NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday

through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the EPA Docket Center is (202) 566-1742.

Instructions. Direct your comments to Docket ID No. EPA-HQ-OAR-2017-0483. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be CBI or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or email. This type of information should be submitted by mail as discussed in the **ADDRESSES** section of this preamble.

The EPA may publish any comment received to its public docket. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.*, on the Web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit https://www2.epa.gov/dockets/commenting-epa-dockets.

The http://www.regulations.gov Web site is an "anonymous access" system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through http://www.regulations.gov, your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you

submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at http://www.epa.gov/dockets.

Preamble Acronyms and Abbreviations. A number of acronyms and abbreviations 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
AVO	Auditory, Visual, and Olfactory
boe	Barrels of Oil Equivalent
BSER	Best System of Emissions Reduction
CAA	Clean Air Act
CBI	Confidential Business Information
CFR	Code of Federal Regulations
CO2 Eq.	Carbon dioxide equivalent
CVS	Closed Vent System
EPA	Environmental Protection Agency
FTE	Full Time Equivalent
GHG	Greenhouse Gases
GHGRP	Greenhouse Gas Reporting Program

LDAR	Leak Detection and Repair
NDE	No Detectable Emissions
NEMS	National Energy Modeling System
NSPS	New Source Performance Standards
NTTAA	National Technology Transfer and Advancement Act
OGI	Optical Gas Imaging
OMB	Office of Management and Budget
PE	Professional Engineer
PRA	Paperwork Reduction Act
PRV	Pressure Relief Valve
REC	Reduced Emissions Completion
RFA	Regulatory Flexibility Act
RIA	Regulatory Impact Analysis
TSD	Technical Support Document
UMRA	Unfunded Mandates Reform Act
VOC	Volatile Organic Compounds
VRU	Vapor Recovery Unit

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

I. General Information
A. Does this action apply to me?
B. What should I consider as I prepare my comments to the EPA?
C. How do I obtain a copy of this document and other related information?
II. Background
III. Legal Authority
IV. The Proposed Action
V. Discussion of Provisions Subject to Reconsideration

A. Pneumatic Pumps
B. Fugitive Emissions from Well Sites and Compressor Stations
C. Professional Engineer Certifications
D. Alternative Means of Emission Limitation (AMEL)
E. Other Reconsideration Issues Being Addressed
VI. Implementation Improvements
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B. Storage Vessels
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B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs
C. Paperwork Reduction Act (PRA)
D. Regulatory Flexibility Act (RFA)
E. Unfunded Mandates Reform Act (UMRA)
F. Executive Order 13132: Federalism
G. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments
H. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks
I. Executive Order 13211: Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use
J. National Technology Transfer and Advancement Act (NTTAA)
K. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

I. General Information

A. Does this action apply to me?

Categories and entities potentially affected by this action include:

TABLE 1. 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. This table lists the types of entities that the EPA is now aware could potentially be affected by this action. Other types of entities not listed in the table could also be regulated. To determine whether your entity is regulated by this action, you should carefully examine the applicability criteria found in the final rule. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section, your air permitting authority, or your EPA Regional representative listed in 40 CFR 60.4 (General Provisions).

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

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

Do not submit information containing CBI to the EPA through *www.regulations.gov* or email. Send or deliver information identified as CBI only to the following address: OAQPS

Document Control Officer (C404-02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Docket ID Number EPA-HQ-OAR-2017-0483. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD-ROM that you mail to the EPA, mark the outside of the disk or CD-ROM as CBI and then identify electronically within the disk or CD-ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

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

In addition to being available in the docket, an electronic copy of the proposed action is available on the Internet. Following signature by the Administrator, the EPA will post a copy of this proposed action at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry*. Additional information is also available at the same Web site.

II. Background

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 OOOOa"). The 2016 NSPS OOOOa established NSPS for greenhouse gas and volatile organic compound (VOC) emissions from the oil and natural gas sector. For further information on the 2016 NSPS 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 OOOOa. Copies of

the petitions are provided in rulemaking docket EPA-HQ-OAR-2017-0483. A number of states and industry associations sought judicial review of the rule, and the litigation is currently being held in abeyance.

In a letter to petitioners dated April 18, 2017, the EPA granted reconsideration of the fugitive emissions requirements at well sites and compressor stations.[1] In a subsequent notice, the EPA granted reconsideration of two additional issues: well site pneumatic pump standards and the requirements for certification of closed vent systems (CVS) by a professional engineer.[2] This action proposes amendments and clarifications to address these issues, and grants reconsideration and proposes amendments to address several additional reconsideration issues, detailed in Section VI below. In addition, since the publication of the 2016 NSPS OOOOa, the EPA has received numerous questions relative to the implementation of the 2016 NSPS OOOOa requirements. This action also addresses these broad implementation issues that have been brought to the EPA's attention. The EPA believes that addressing these issues at the same time will provide clarity and certainty for the public and the regulated community with regard to these requirements.

III. Legal Authority

This action, which proposes certain amendments to the 2016 NSPS OOOOa, is based on the same legal authorities as those for the promulgation of that rule. The EPA promulgated the 2016 NSPS 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) requires the EPA to issue "standards of performance" for new sources in a category listed by the Administrator based on a finding that this category of

[1] See Docket ID No. EPA-HQ-OAR-2010-0505-7730.
[2] 82 FR 25730.

stationary sources causes or contributes 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." This definition makes clear that the standard of performance must be based on controls that constitute "the best system of emission reduction. . . adequately demonstrated." The standard that the EPA develops, based on the best system of emission reduction (BSER), is commonly a numerical emissions 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 reflects the best technological system of continuous emission reduction, if it is not feasible to prescribe or enforce an emissions standard. This action includes proposed 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)(A). 81 FR 35829.

The proposed amendments in this notice result from the EPA's reconsideration of various aspects of the 2016 NSPS 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 Television 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).

IV. The Proposed Action

In this action, we are proposing amendments and clarifications on the following set of issues as a result of reconsideration: (1) pneumatic pump requirements; (2) fugitive emissions requirements at well sites and compressor stations; (3) professional engineering certification for CVS design and pneumatic pump technical infeasibility; and (4) alternative means of emissions limitations. In addition, we are proposing amendments to a number of other aspects of 2016 NSPS OOOOa, including well completion requirements and requirements at onshore natural gas processing plants. This action also addresses broad implementation issues that have been brought to the EPA's attention. Finally, we are proposing to correct technical errors that were inadvertently included in the final rule.

This document is limited to the specific issues identified in this notice. We will not respond to any comments addressing any other provisions of the 2016 NSPS OOOOa.

V. Discussion of Provisions Subject to Reconsideration

As summarized above, the EPA is proposing to address a number of issues that have been raised by different stakeholders through several administrative petitions for reconsideration of the 2016 NSPS OOOOa. The following sections present the issues raised by the petitioners that the EPA is addressing in this action and how the EPA proposes to resolve the issues.

A. Pneumatic Pumps

1. Definition of a Greenfield Site

The 2016 NSPS OOOOa includes a technical infeasibility provision from the well site pneumatic pump requirements for circumstances such as insufficient pressure or control device

capacity. 81 FR 35850. This provision was not provided for pneumatic pumps at greenfield sites (defined as a site, other than a natural gas processing plant, which is entirely new construction). *Id.* Petitioners stated that the term greenfield site was inadequately defined. For example, one petitioner questioned whether the term "new" as used in this definition is synonymous to how that term is defined in section 111 of the CAA. Additional questions included whether a greenfield remains forever a greenfield, considering that site designs may change by the time that a new control or pump is installed (which may be years later). Petitioners also objected to the EPA's assumption that the technical infeasibility encountered at existing well sites can be addressed when "new" sites are developed.

We previously concluded that circumstances, such as insufficient pressure or control device capacity, that could otherwise make control of a pneumatic pump technically infeasible at an existing location could be addressed in the site's design and construction. 81 FR 35850. However, petitioners have raised the concern that even at a greenfield site, there may be unique process or control design requirements that may not be compatible with controlling pneumatic pump emissions. Petitioners contend that such circumstances include the following:

- A new site design requires only a high-pressure flare to control emergency and maintenance blowdowns, and it is not feasible for a low pressure pneumatic pump discharge to be routed to such a flare; and
- A new site design requires only a small boiler or process heater, but such boiler or process heater could be insufficient to control pneumatic pumps emissions and routing pneumatic pump emissions to the boiler or process heater could result in safety trips and burner flame instability.

It is not clear that the scenarios described above present circumstances where it may be technically infeasible despite the site being newly designed and constructed; we therefore solicit comment on these examples, as well as other examples of technical infeasibility for a greenfield site. Regardless, while the EPA believes that most claims of technical infeasibility can be accounted for in the design and construction of a new site by selecting a control device or process that can control additional pneumatic pump emissions (*e.g.*, selecting a flare or slightly larger boiler that can accommodate such flows) with little additional cost, we cannot rule out the possibility that there could be infrequent cases of technical infeasibility at a greenfield site despite design and construction choices. We are therefore proposing to expand the technical infeasibility provision to all well sites by eliminating the distinction between greenfield sites and non-greenfield sites for the pneumatic pump requirements. The proposal would avoid the potential of requiring a greenfield from controlling the pneumatic pump emissions should it be technically infeasible to do so, while having no impact on the compliance obligations of other greenfield sites that do not have this issue. We solicit comment on this proposal. In addition, we solicit comment on site and control configurations that could present technical infeasible scenarios at a new construction site. We also solicit comment on information related to the additional costs that may be incurred if an owner or operator selects a control that can accommodate pneumatic pump emissions in addition to the control's primary purpose at a new construction site.

B. Fugitive Emissions from Well Sites and Compressor Stations

1. Monitoring Frequency

Monitoring Frequency for Well Sites. The 2016 NSPS OOOOa requires initial monitoring within 60 days of the startup of production and subsequent semiannual monitoring of the

collection of fugitive emissions components located at all well sites. We received petitions requesting changes to several aspects of fugitive monitoring frequencies: (1) a pathway to less frequent monitoring, (2) an exemption for low production well sites, and (3) an exemption for well sites located on the Alaskan North Slope. As discussed in detail in the following subsections, the EPA is proposing the following amendments to the fugitive emissions monitoring frequency for the collection of fugitive emissions components located at well sites:

- Semiannual monitoring for two years, followed by annual monitoring at well sites with average combined oil and natural gas production for the wells at the site being greater than or equal to 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production ("non-low production well sites");
- Annual monitoring for well sites with average combined oil and natural gas production for the wells at the site being less than 15 boe per day averaged over the first 30 days of production ("low production well sites");
- 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; and
- Annual monitoring and separate initial monitoring requirements for well sites and compressor stations located on the Alaskan North Slope.

Pathway to Less Frequent Monitoring. Several petitioners requested that the EPA reconsider the frequency of monitoring to include a pathway to less frequent monitoring, specifically annual monitoring for well sites and semiannual monitoring for compressor stations.[3] In the 2015 NSPS OOOOa proposal, the EPA proposed alternative monitoring frequencies that would adjust up and down in frequency based on the percentage of fugitive emissions

[3] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682, EPA-HQ-OAR-2010-0505-7685 and EPA-HQ-OAR-2010-0505-7686.

components identified with fugitive emissions during monitoring events. For instance, if the first two semiannual monitoring surveys resulted in less than one percent of the collection of fugitive emissions components with fugitive emissions, then the well site could have moved to annual monitoring. For well sites with more than three percent of the fugitive emissions components identified with fugitive emissions, quarterly monitoring would have been required. However, as noted in the preamble to the 2016 NSPS OOOOa,[4] the commenters opposed this approach and raised specific concerns that performance-based monitoring frequencies would be costly, time-consuming, and impose a complex administrative burden for the industry and states. Noting the additional administrative burden and the potential issues with operating permits, we concluded in that rulemaking that "the potential for a performance-based approach to encourage greater compliance is outweighed in this case by the additional burdens and the complexity it would add."[5] Therefore, the monitoring frequencies established in the 2016 NSPS OOOOa were fixed at semiannual for well sites and quarterly for compressor stations based on the BSER analysis.

One petitioner asserts that the EPA's cost-effectiveness analysis is not accurate and should be revised.[6] In support, the petitioner provided data (which is described in more detail below). The petitioner suggested that, at a minimum, the EPA should require semiannual monitoring at well sites for an initial period of 2 years followed by less frequent monitoring frequencies such as annual monitoring for sites that do not have a significant number of "leaking"[7] components.[8] In addition, the petitioners suggested there should be a pathway out of monitoring when production declines such that the well site would be considered a low

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[4] See 81 FR 35857.
[5] See 81 FR 35857.
[6] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.
[7] While the petitioner used the term leaking, the EPA is clarifying they were referring to fugitive emissions, and not equipment leaks such as those subject to a leak detection and repair (LDAR) program at onshore natural gas processing plants.
[8] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.

production well site. Low production well sites are discussed in a separate subsection of this preamble, and as discussed in that subsection, we are proposing annual monitoring for low production well sites. While we are not providing a pathway out of monitoring because of production levels, as discussed in this subsection, we are proposing a pathway out of monitoring once the major production and processing equipment is removed from the well site.

As mentioned above, the petitioner provided information in order to demonstrate lower percentages of fugitive emissions than used in the EPA's analysis. However, this information was limited to Colorado and the Barnett Shale region of Texas, and may not represent the percent of fugitive emissions realized in other areas with heavy oil and natural gas production activities.[9] This information included the number of components with fugitive emissions by component type, an estimate of the total number of each component type, and an estimated percentage of fugitive emissions components identified with fugitive emissions using both OGI and Method 21 of Appendix A-7 to Part 60 ("Method 21"). Subsequent to the submission of their petition, this petitioner also provided additional data on the initial fugitive emissions percentages for well sites located in 14 states.[10] While the letter from the petitioner stated that on average 0.4 percent of fugitive emissions components were identified with fugitive emissions, this percentage was based on the aggregation of fugitive emissions by dividing the total number of fugitive emissions components identified with fugitive emissions by the total estimated number of fugitive emissions components monitored, and thus did not address the average percentage of fugitive emissions components found with fugitive emissions at individual well sites. Accordingly, as presented by the petitioner, the data could not be directly transferred to our

[9] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.
[10] Alaska, Arkansas, Colorado, Louisiana, Montana, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, Utah, West Virginia, and Wyoming.

model plant. Instead, the EPA has evaluated the data provided to determine the average percentage of fugitive emissions components identified with fugitive emissions at the individual well site level, consistent with our treatment of well site fugitive emissions. For the individual well sites, this percentage ranged from 0 percent to 13.47 percent. This results in an average percentage of 0.54 percent or an average of 2 components per well site per survey with fugitive emissions.[11] This contrasts with the EPA's estimate of 4 components per well site per survey with fugitive emissions, or 1.18 percent, used in the 2016 NSPS OOOOa. Additional information on our evaluation of this data is included in the memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API*, located at Docket ID No. EPA-HQ-OAR-2017-0483. While we have not incorporated any changes to the model plants as a result of these data from the petitioner, we did evaluate each of the options using both average percentages (0.54 and 1.18 percent), as discussed further in this section, and reached the same conclusions. We are soliciting comment on these data relevant to the determination of the average percentage of fugitive emissions components identified with fugitive emissions and our evaluation of the data. Additionally, we are soliciting additional information that would suggest a different percentage should be considered, including counts of the components monitored, the number of identified fugitive emissions, the type of fugitive emissions components monitored, the type of fugitive emissions components found with fugitive emissions, the production levels of the wells located at the well site, age of the wells at the well site, location of the well site, and how the surveys were performed, including the monitoring instrument used and the regulatory program followed. As discussed further below, we are particularly interested in how these variables differ over time and comparisons of facilities implementing fugitive emissions programs and those that have not.

[11] See memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 17, 2018.

In addition to the percentage of fugitive emissions components identified with fugitive emissions, the EPA has evaluated other available information and updated the well site model plants. We updated the model plants used in support of the 2016 NSPS OOOOa based on updates in the Greenhouse Gas Inventory (GHGI) program for major equipment counts at well sites. Specifically, the number of meters/piping decreased from 3 to 2 for the gas well site and oil with associated gas well site model plants. No changes were made to the oil well site model plant as a result of updates in the GHGI.

In addition to updates made based on updates to the GHGI, we also added one controlled storage vessel per model plant and an emissions factor for pressure relief devices (PRDs), such as thief hatches and pressure relief valves (PRVs) from these controlled storage vessels because controlled storage vessels that are not affected facilities subject to the requirements in 40 CFR 60.5395a are considered fugitive emissions components. In evaluating the quantity of fugitive emissions from storage vessels, we considered data indicating that the frequency of fugitive emissions from controlled storage vessels may be much higher than that for other fugitive emissions components. For purposes of the model plant, we are adding one controlled storage vessel with one PRD. We are aware that owners and operators may be claiming that many of their controlled storage vessels are subject to the fugitive emissions programs rather than affected facilities subject to the requirements in 40 CFR 60.5395a for storage vessels with the potential to emit greater than 6 tpy of VOC (suggesting that we should be adding more than one controlled storage vessel to the model plant).[12] However, as discussed further in section V.B., many of these claims of exclusion may be improper, meaning that the number of controlled storage vessels under the fugitive emissions program may be overstated. Accordingly, even our

[12] See the TSD for additional information on the fugitive emissions from storage vessels.

estimate of one controlled storage vessel per well site that may be subject to the fugitive emissions program may be an overestimate. We are soliciting comment on our assumption of one controlled storage vessel per well site subject to fugitive emissions requirements and data to further refine the model plant with regards to controlled storage vessel fugitive emissions. The emissions factor used for PRDs on controlled storage vessels was derived from a study that conducted aerial surveys for emissions at oil and gas production sites located in seven basins across the United States.[13] We did not update the average emissions factors for other fugitive emissions components based on information in this study because the study stated that emissions from individual components, such as valves, could not be identified during the surveys. In this study, helicopter-based OGI monitoring was performed at 8,220 well sites. A total of 494 fugitive emission sources were identified at 327 sites, averaging approximately 1.5 fugitive sources per site. Fugitive emissions[14] from storage vessels accounted for 92 percent of the total fugitive sources, with 198 fugitive sources associated with storage vessel PRVs and 257 fugitive sources associated with thief hatches, though it was unclear from the study if all of these storage vessels were equipped with a CVS that routes emissions to a control device. The estimated detection limit for the OGI instrument observed by this study was 1 gram per second (g/s) for heavier hydrocarbons and 3 g/s for methane.[15] Based on this information, we used the 1 g/s estimated emission rate in combination with the frequency of storage vessel emissions identified in the study to estimate emissions from thief hatches for purposes of the model plants. However, we acknowledge that the emissions are likely underestimated when using this information

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[13] Lyon, David R., et al., *Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites*. Environmental Science and Technology 2016, 50, 4877-4886.

[14] It was difficult for the Lyon, David R., et al., study to attribute emissions from storage vessels to specific malfunctions or normal operations. The study predicted liquid unloading events and stuck open separator dump valves would contribute less than 0.1% of the emissions detected for each event. The other 99.8% of the storage vessel emissions were not characterized by the study. See *Id.* at pages 4882-4883.

[15] *Id.*

because small or medium sized emissions would not be visible during an aerial OGI survey. Additional information about the model plants and analysis is included in the Background Technical Support Document (TSD) located at Docket ID No. EPA-HQ-OAR-2017-0483.

Emissions for the other fugitive emissions components were estimated using average emissions factors for oil and gas production operations, found in Table 2-4 of the *Protocol for Equipment Leak Emission Estimates* (1995 Protocol).[16] These average emissions factors are used when screening data are not available, as is the case when OGI is used as the monitoring instrument,[17] and provide an average emission rate for the collection of fugitive emissions components at the site. For example, the average emissions factors can be used to estimate emissions from the collection of all valves at the site, instead of needing to estimate emissions from each individual valve and averaging the emissions across the collection of valves. In addition to the information regarding the percentage of fugitive emissions components identified with fugitive emissions, the petitioner also presented updated emissions factors for these fugitive emissions components.[18] The petitioner attempted to create new average emissions factors by using the newly presented 0.4 percent for identified fugitive emissions and scaling the average emissions factors documented in the 1995 Protocol. We do not agree with the approach of scaling emissions factors presented by the petitioner for the non-storage vessel PRD fugitive emissions components and have not evaluated the cost of control using these scaled factors. Additional information on our evaluation of the scaled emissions factors is included in the memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API*,

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[16] U.S. Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates. Table 2-4. November 1995 (EPA-453/R-95-017).

[17] OGI instruments that are currently widely available provide a qualitative indication of emissions and do not provide an indication of the concentration levels of fugitive emissions. However, we recognize that quantitative OGI is a new technological development that may allow estimations of mass emission rates in the future.

[18] See memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 17, 2018.

located at Docket ID No. EPA-HQ-OAR-2017-0483. Therefore, we continue to use the average emissions factors in the 1995 Protocol to calculate emissions in the model plants for the fugitive emissions components, excluding controlled storage vessel PRDs.

Since we continue to utilize the average emissions factors, the emissions were not affected by the percentage of fugitive emissions components identified with fugitive emissions. When estimating the costs of the fugitive emissions program at well sites, the only place we account for this percentage is related to the cost of repairs. As noted previously, there is a difference of two components identified with fugitive emissions per well site when using the petitioner's reported average of 0.54 percent and our estimate of 1.18 percent. The difference in repair costs for the proposed monitoring frequency discussed below is $70. We have evaluated the cost of control using both the 0.54 and 1.18 percent values and reached the same conclusions regarding which option is reasonable, therefore we have maintained the 1.18 percent as the estimated percentage of fugitive emissions components identified with fugitive emissions in this proposal. Additional information about this analysis is available in the TSD.

After updating the model plants, the EPA performed a sensitivity analysis to understand how the monitoring frequencies would affect emission reductions and costs. We examined the costs and emission reductions for the non-low production model plant at semiannual, annual, and stepped (semiannual for 2 years to annual) monitoring frequencies. We applied the two approaches used in the 2016 NSPS OOOOa (single and multipollutant approaches)[19] for

[19] See 81 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 equally controlled, therefore half of the cost is apportioned to the methane emission reductions and half of the cost if apportioned to the VOC emission reductions. In this evaluation, we examined both approaches across the range of identified monitoring frequencies: semiannual, annual, and semiannual for 2 years followed by annual.

evaluating cost-effectiveness of these various monitoring frequencies applied to the fugitive emissions program for reducing both methane and VOC emissions from non-low production well sites.

As shown in the TSD, for semiannual monitoring of non-low production well sites, under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,164 per ton of methane reduced, and $965 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,186 per ton of VOC reduced, and $3,473 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $2,093 per ton VOC reduced, and $1,736 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $582 per ton methane reduced, and $483 per ton if natural gas savings are considered.[20]

While the cost of control for semiannual monitoring appears to be reasonable, we recognize several limitations with our estimates of the emission reductions and implementation costs, which likely result in a significant overstatement of the cost-effectiveness of control on an ongoing basis. First, the cost of control presented here and in the TSD are based on the implementation of a fugitive emissions program where monitoring has not previously occurred. The baseline emissions represented in the non-low production model plants are based on uncontrolled fugitive emissions, that is, emissions that would go unmitigated without a monitoring and repair program. Further, each monitoring frequency has a corresponding emission reduction based on expected control efficiencies of the OGI-based monitoring program

[20] See the TSD for full comparison of cost.

at the various monitoring frequencies. Thus, in our cost-effectiveness analysis the emission reductions are assumed to be constant over the life of the fugitive emissions program at each individual well site.

Additionally, the model plants assume that the percentage of components found with fugitive emissions remains the same throughout the life of the fugitive emissions program. This assumption that the percentage do not change over time is in contrast with how we have evaluated similar programs aimed at fugitive emissions. When we have evaluated the implementation of a new leak detection and repair (LDAR) program where monitoring was not previously required in other actions, we have recognized that initial percentages of leaks are generally higher than subsequent leak percentages for the non-storage vessel PRD fugitive emissions components.[21] As an LDAR program is implemented, leak percentages decline until they reach a "steady state". As illustrated in Figure 5-35 of the *Protocol for Equipment Leak Emission Estimates*,[22] the highest leak percentage is identified during the first monitoring event. The leak percentage then declines over time and reaches a point of steady state where the leak percentage is lower than that identified in the first monitoring event. Additional discussion of the leak percentages, including a discussion of the information evaluated related to leak percentages, is included in the TSD.

In this action, the EPA seeks to incorporate this understanding, that initial percentages of fugitive emissions components identified with fugitive emissions are higher than subsequent percentages in a newly implemented fugitive emissions program. We know that, by assuming constant emission reductions every year (without taking into account the reduced percentages as

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[21] See *Final Impacts Analysis for Regulatory Options for Equipment Leaks of VOC in the SOCMI*, located at Docket ID. EPA-HQ-OAR-2006-0699-0090 at p. 8.
[22] U.S. Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates. Section 5.3 and Figure 5-35. November 1995 (EPA-453/R-95-017).

the program is implemented), we have overestimated the emission reductions and therefore the cost-effectiveness of the various monitoring frequencies as the program continues. Therefore, while semiannual monitoring is cost effective when it is first implemented, as reflected in our cost analysis described above, we do not have information to conclude that semiannual monitoring remains cost-effective as the percentage of fugitive emissions declines and approaches a "steady state." While we do not have enough information to determine how long it takes for this percentage to reach a "steady state," we recognize that certain existing LDAR requirements, such as those for natural gas processing plants in 40 CFR 60.5400a(b), allow for less frequent monitoring, such as annual monitoring, after a period of 5 consecutive quarters. This suggests that steady state may be reached at around 2 years of implementation of a monitoring and repair program. Therefore, we are proposing that well sites will reach this steady state within 2 years. In light of the above, we propose to change the current monitoring frequency for non-low production well sites from a permanent semiannual monitoring frequency to semiannual monitoring for an initial 2-year period and annual monitoring frequency thereafter. We solicit comment and data to help us better understand what this "steady state" percentage may be for fugitive emissions components from semiannual monitoring, how long it takes for the program to reach such a state after monitoring begins, and any other relevant information that would help either confirm or eliminate our concern regarding the long-term cost-effectiveness of semiannual monitoring.

There are several well sites that incorporated fugitive monitoring programs prior to the 2016 NSPS OOOOa for various purposes, including compliance with state or local requirements. We are soliciting data regarding the percentage of fugitive emissions components identified with fugitive emissions at these well sites for each survey performed to understand how this

percentage may change over time; the data should include information on when the well site began producing, the start date of the fugitive program at the well site, the frequency of monitoring, an indication of the location of the well site *(e.g.,* basin name or state), and how the surveys are performed, including the monitoring instrument used and the regulatory program followed. We are also soliciting comment and supporting data related to annual monitoring, without the step down, for well sites.

The EPA is soliciting information that can be used to evaluate if additional changes are necessary to the model plants. Specifically, the EPA requests information that has been collected from implementing fugitive monitoring programs, including information on leak concentrations where Method 21 has been used for monitoring. This information could also demonstrate the actual equipment counts or fugitive emissions component counts at the well site, in relation to the number of fugitive emissions identified during each monitoring survey. Additionally, the EPA is soliciting information that can be used to further refine the emission reductions achieved with OGI-based monitoring at the various monitoring frequencies. As discussed in the TSD, the EPA estimates 40 percent emission reduction for annual monitoring, 45 percent for the stepped monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring. While these emission reductions were based on the best available information, the EPA is aware there may be studies that may provide additional analysis on the effectiveness of OGI monitoring that can further refine our estimates. Specifically, the EPA is requesting information on any analyses performed on the effectiveness of OGI monitoring at different monitoring frequencies and the data underlying these analyses, including information on how the data was gathered, what the date represents, and how the analysis was performed.

Further, we are proposing that fugitive monitoring may stop when an owner or operator removes all major production and processing equipment from the well site, such that it contains only one or more wellheads. The 2016 NSPS OOOOa excludes well sites that contain only one or more wellheads from the fugitive emissions requirements because fugitive emissions at such well sites are extremely low. 80 FR 56611. In the preamble to the 2015 NSPS OOOOa proposal, we noted that wellhead only well sites do not have ancillary equipment (such as storage vessels, closed vent systems, control devices, compressors, separators, and pneumatic controllers), thus resulting in low emissions. For the same reason, we anticipate that, when a well site becomes a wellhead only well site due to the removal of all ancillary equipment, its fugitive emissions would also be extremely low because the number of fugitive emissions components is low. This proposal uses the term "major production and processing equipment" to refer to ancillary equipment without which the fugitive emissions would be extremely low. We are, therefore, proposing to define "major production and processing equipment" as including separators, heater treaters, storage vessels, glycol dehydrators, pneumatic pumps, or pneumatic controllers. We have also evaluated the cost-effectiveness of monitoring a wellhead only well site and find it not to be cost-effective. For that analysis, we developed a model plant that contains only 2 wellheads and no major production and processing equipment. For the annual monitoring frequency, we found the cost for control was greater than $5,000 per ton of methane reduced and greater than $20,000 per ton of VOC reduced.[23] Additional discussion about this model plant and the cost of control is included in the TSD. In light of the above, we are proposing that monitoring may discontinue when all major production and processing equipment at a well site has been

[23] We did not perform an analysis for the cost of control at a semiannual monitoring frequency for these wellhead only well sites because we determined that annual monitoring was not cost-effective. Therefore, at more frequent monitoring, it would also not be cost-effective because there are higher costs compared to annual monitoring.

removed, resulting in a wellhead only well site. We are soliciting comment on the proposed exemption and definition of major production and processing equipment for purposes of this specific proposal, including whether additional equipment should be included in this list, such as compressors and engines.

As explained above, we are proposing that monitoring is no longer required when all major production and processing equipment at a well site has been removed, resulting in a wellhead only well site. We note that if the production from this well site (with all major production and processing equipment removed), is sent to a separate tank battery for processing, that separate tank battery (which itself is a well site as defined in 40 CFR 60.5430a) is considered modified and subject to the fugitive emissions requirements. Additional discussion on this topic is included in section V.B.2 of this preamble. We further note that the proposed monitoring exemption would not change the affected facility status of the collection of fugitive emissions components located at a well site that removes equipment to become a wellhead only well site; it would remain an affected facility. We are proposing to require that owners or operators report the following information in the next annual report following the change to a wellhead only well site: (1) a statement that the well site has removed all major production and processing equipment, (2) the final date that equipment was removed, (*i.e.,* the date that the well site began meeting the definition of a wellhead only well site), and (3) the location receiving the production from the well site. Provided the well site remains a wellhead only well site, no additional reporting related to fugitive emissions would be required. If in the future production equipment is reintroduced to the well site, the fugitive emissions requirements would restart with initial monitoring followed by the subsequent monitoring, the frequency of which would be based on the subcategory (non-low production or low production) that the well site was classified

as when it first became an affected facility for fugitive emissions requirements (e.g. not the subcategory that the well site is classified when production equipment is reintroduced). We are soliciting comment on this proposed exemption from monitoring for well sites that become wellhead only sites, including the proposed reporting requirements and subsequent monitoring requirements should the wellhead only status of the well site later change.

Low Production Well Sites. The 2016 NSPS OOOOa requires semiannual monitoring for all well sites, regardless of the production levels for the well site. In 2015, the EPA proposed to exclude low production well sites (*i.e.,* well sites where the average combined oil and natural gas production is less than 15 boe per day averaged over the first 30 days of production) from fugitive emissions requirements. 80 FR 56639. It was our understanding in 2015 that fugitive emissions were low at low production well sites and that these well sites were mostly owned and operated by small businesses. We were concerned about the burden on small businesses, especially with relatively low emission reduction potential. *Id.* However, in the preamble to the 2016 NSPS OOOOa, the EPA stated that we "believe that low production well sites have the same type of equipment (*e.g.,* separators, storage vessels) and components (*e.g.,* valves, flanges) as well sites with production greater than 15 boe per day. Because we did not receive additional data on equipment or component counts for low production wells, we believe that a low production well model plant would have the same equipment and component counts as a non-low production well site." 81 FR 35856. We based this conclusion on the fact that we had no data to indicate that the number and types of equipment were different at low production well sites than at non-low production well sites. Additionally, comments received on the 2015 proposal indicated that small businesses would not benefit from the proposed exemption because

these types of wells would not be economical to operate and few operators, if any, would operate new low production well sites. *Id.*

In a letter dated April 18, 2017, the Administrator granted reconsideration of several aspects of the 2016 NSPS OOOOa, including applying the fugitive emissions requirements at 40 CFR 60.5397a to low production well sites.[24] The petitioner who raised this issue for reconsideration identified in its petition what they classified as an inconsistency between the EPA's justification for not exempting low production well sites from the fugitive emissions requirements and the EPA's rationale for the definition of modification for purposes of those same requirements.[25] This petitioner observed that it appeared the EPA relied on data indicating the same equipment counts were present at all well sites regardless of production levels to justify regulating fugitive emissions at low production well sites, while defining modification by events that increase production (*i.e.*, drilling a new well, hydraulic fracturing a well, or hydraulic refracturing a well), which the EPA concludes will increase emissions whether or not there is change in component counts. The petitioner then stated that:

> "EPA's rationale, that fugitive emissions are a function of the number and types of equipment, and not operating parameters such as pressure and volume, is inconsistent with EPA's justification for what constitutes a "modification" for an existing well site. EPA assumes that fracturing or refracturing an existing well will increase emissions because of the additional production, *i.e.*, the additional pressure and volume. EPA cannot ignore the laws of physics to the detriment of low production wells in one instance and then "honor" them in another context to eliminate an "emissions increase" requirement in the traditional definition of "modification."[26]

As we explain in detail in section V.B.2 related to modifications, operating pressures and volumes are one set of factors that can cause changes in the fugitive emissions at a well site.

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[24] See Docket ID No. EPA-HQ-OAR-2010-0505-7730.
[25] See Docket ID No. EPA-HQ-OAR-2010-0505-7685.
[26] See Docket ID No. EPA-HQ-OAR-2010-0505-7685, p. 5.

However, as described below, we also agree with other petitioners that equipment counts can vary based on the amount of production at a well site.[27]

The petitioners noted that as production increases it is possible that additional major production and processing equipment is added to the well site to handle this increase. The opposite impact was also presented by petitioners, in that as production declines, major production and processing equipment is either disconnected or removed from the well site so it can be used somewhere else.[28] Additionally, the petitioners noted that operating pressures for the well site are generally affected by production, and depleted wells may not be able to provide enough pressure to meet the pressure requirements of the gas gathering system.[29] In comments submitted on the November 2017 Notice of Data Availability ("2017 NODA"), one commenter noted that the information used as the basis for the EPA's decision to treat low production well sites the same as non-low production well sites was based on a flawed analysis of the data.[30] This commenter noted that emissions were presented in such a way as to compare the total well site emissions as a percentage of production. As noted by the commenter, this type of analysis unfairly makes it appear that low production well sites are "super-emitters" because when emissions are compared based on a percentage of production, even small emissions can appear to be upwards of 50 percent or more of the total production for the well site. Further, one petitioner reiterated concerns about the impacts of fugitive emissions requirements on small businesses, including stating that the "marginal profitability will mean that many wells will be shut in instead of making the investment to conduct LDAR surveys."[31] While we currently do not have

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[27] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.
[28] See Docket ID No. EPA-HQ-OAR-2010-0505-7682, p. 12.
[29] *Id.*
[30] See Docket ID No. EPA-HQ-OAR-2010-0505-12454.
[31] See Docket ID No. EPA-HQ-OAR-2010-0505-7685.

information supporting this assertion, we solicit information confirming or refuting this concern including analyses on the number of wells that may be shut in as a result of requiring fugitive emissions monitoring and how these concerns may vary based on production level (presumably wells with higher production would be better able to adsorb more frequent monitoring). At a minimum, any information provided should include the costs of implementing the fugitive emissions requirements compared to the profitability of the well site over the life of the well site from first production through shut in. Further, any information provided should include information as to the length of the life of the well site, beginning at first production, and by how much that total duration would be shortened by the shut in, as well as information as to total production over the life of the well site, beginning at first production, and the amount of production that would be reduced by the shut in. If information received supports the allegation that fugitive emissions monitoring would lead to a significant number of shut-ins at a significantly earlier point in the life of the well site and with a significant loss of overall production volume, that would further support our proposals regarding monitoring frequency. However, assertions presented without supporting information will not be deemed helpful related to this discussion.

In light of the comments, the petitions, and data made available after promulgation of the 2016 NSPS OOOOa, the EPA has re-examined whether fugitive emissions are different for low production well sites. Following promulgation of the 2016 NSPS OOOOa, the EPA received information from one stakeholder which contained component level emissions information for well sites in the Dallas/Fort Worth area (herein referred to as the "Fort Worth Study").[32] The EPA evaluated the emissions calculation workbook included in Appendix 3-B of the Fort Worth

[32] "The Natural Gas Air Quality Study (Final Report)", prepared by Eastern Research Group, Inc. July 13, 2011, available at *http://fortworthtexas.gov/gaswells/air-quality-study/final/*.

Study and was able to identify 27 well sites with throughput less than 90 thousand cubic feet per day (Mcfd), or 15 boe per day. While this throughput was the throughput reported for the prior day and not the average over the first 30 days as we are defining low production well sites in this proposed reconsideration, this information was relevant to understanding both component counts and emissions for the well sites in the study as compared to production values. As explained in the memorandum *Analysis of Low Production Well Site Fugitive Emissions from the Fort Worth Air Quality Study* ("Fort Worth Study Memo"), located at Docket ID No. EPA-HQ-OAR-2017-0483, the EPA was able to directly compare fugitive component emissions from these 27 low production well sites to the fugitive component emissions from the other approximately 300 well sites in the study. This evaluation demonstrated that average emissions across the low production well sites were lower than those at the non-low production well sites in the study. Additionally, the average equipment counts were also lower for the low production well sites than those at non-low production well sites in the study. When fugitive emissions were considered from non-tank and non-controller fugitive sources, the average methane emissions were approximately 2.5 tpy for low production well sites, and 24 tpy for non-low production well sites. When storage vessel fugitives (*e.g.*, thief hatches) were considered, average methane emissions were 13 tpy for low production well sites and 33 tpy for non-low production well sites.[33]

Given this information, the EPA evaluated fugitive emissions from well sites by subcategorizing well sites based on production: (1) non-low production and (2) low production. Within each of these subcategories, the EPA modified the three model plants used in the 2016 NSPS OOOOa: gas well site, oil well site (defined as GOR <300), and oil with associated gas

[33] See the memorandum *Analysis of Low Production Well Site Fugitive Emissions from the Fort Worth Air Quality Study*, located at Docket ID No. EPA-HQ-OAR-2017-0483.

well site (defined as GOR ≥300). A discussion of the non-low production well site model plants is included in the previous discussion on the pathway to less frequent monitoring.

The EPA created new model plants using the component count information obtained for the low production well sites in the Fort Worth Study in order to compare the emissions using the emissions factors used by the EPA for model plant calculations to the measured emissions from the study. For the low production gas well site model plant, we used the average equipment counts for the low production well sites in the Fort Worth Study. We then compared the corresponding average component counts (*e.g.,* valves, connectors) for this equipment in the low production gas well site to the non-low production gas well site to determine a scaling factor. This scaling factor was applied to the non-low production component counts for the oil well site and oil with associated gas well site model plants in order to evaluate these types of well sites for the low production subcategory. Additional information about the low production well site model plants and analysis is included in the TSD.

As mentioned previously, in the 2016 NSPS OOOOa the EPA did not expect production levels to affect the amount of major production and processing equipment at well sites. However, as discussed above, we have since evaluated data showing that low production wells have fewer equipment, and therefore fewer fugitive emissions components. Therefore, in this proposal, we have incorporated the new data and developed model plants for low production well sites. The estimated emissions and cost-effectiveness are different between the low production and non-low production well site model plants. For example, the estimated baseline methane emissions are 5.91 and 4.80 tpy for non-low production and low production gas well site model plants, respectively. We performed additional analysis on the emissions data presented in the Fort Worth Study to determine if there was a statistical difference between the low production and non-low

production methane emissions. This analysis determined the mean methane emissions were 157 and 116 tpy for non-low production and low production well sites, respectively. Additional information on this analysis is included in the Fort Worth Study Memo located at Docket ID No. EPA-HQ-OAR-2017-0483.

In addition to the Fort Worth Study, the EPA evaluated other available information for comparing low and non-low production well sites. While we did not find the same level of detail regarding component counts to allow us to further refine the low production well site model plants, several of the studies indicated that there is a general correlation between production and fugitive emissions, where fugitive emissions increase as production increases at the well site. Further, some studies indicated that while the number of fugitive emissions components was lower for low production well sites, a few outliers were identified suggesting that all well sites have the potential for fugitive emissions greater than the estimates in the model plants. Finally, the studies also indicated that storage vessel thief hatches were a large source of fugitive emissions when compared to other fugitive emissions components, such as valves and connectors. Additional information about these studies is presented in the memorandum *Low Production Well Site Fugitive Emissions* ("Low Production Memo"), located at Docket ID No. EPA-HQ-OAR-2017-0483.

We examined the costs and emission reductions for the low production model plant at semiannual, annual, and stepped monitoring frequencies using the single and multipollutant approaches discussed previously for non-low production well sites. The calculation of the costs, emission reductions, and cost of control for each option are explained in detail in the TSD. Additionally, as shown in the TSD, while the costs for repairing components that are found to have fugitive emissions during a fugitive monitoring survey remain the same, the annual repair

costs will differ based on the monitoring frequency employed, such that the cost for control of a fugitive emissions program increases as monitoring frequency increases because more repairs are performed. As we stated previously with regard to non-low production well sites, it is important to note that the model plants assume emissions do not change over time, therefore, the cost for control values presented in the TSD may overestimate the cost-effectiveness of each option after the initial monitoring period concludes and the percentage of fugitive emissions reaches a "steady state." For the reasons discussed below, we are not using the cost for control as the basis for the proposed fugitive emissions requirements for low production well sites.

We recognize that our analysis likely overestimates the emission reduction and therefore, the cost-effectiveness of each of the three monitoring frequencies due to several factors. First, similar to the cost analysis for non-low production well sites, the cost analysis for low production well sites does not take into account the declining percentages of fugitive emissions as a monitoring program continues. Second, as we have described previously, the number of each type of major production and processing equipment located at low production well sites may differ from that at non-low production well sites, and we are not certain this has been adequately taken into account with the limited data available[34] from the Fort Worth Study. The equipment that is present at a low production well site is typically designed for lower operating conditions, such as volume and pressure, therefore, the equipment may be smaller and composed of fewer fugitive emission components than those estimated in the model plants. As discussed in further detail in the TSD, we used the average major production and processing equipment counts from the Fort Worth Study as the basis for the low production model plants; however, because the Fort

[34] The site-specific data available in the Fort Worth Study is limited to approximately 300 natural gas well sites located near the City of Fort Worth, Texas. Most of the well sites consisted of dry gas, with no information available on oil well sites. We are uncertain the major production and processing equipment counts presented in this study are representative of well sites located in other areas of the country.

Worth Study does not provide component count data by equipment, we assigned the same average component counts per major equipment (*i.e.,* the same number of valves per separator as the number of valves per separator at non-low production well sites). Therefore, we are concerned that we have overestimated the fugitive emissions component counts for low production well sites. Additionally, the petitioners assert that the operating pressures are much lower for low production well sites than for non-low production well sites, and we do not have a mechanism to account for operating pressure changes in our model plants.[35] However, in section V.B.2 of this preamble, we discuss comments from petitioners stating that operating pressures may be driven, in part, by sales line pressures such that decreased production levels may not allow for operations below the gas sales line pressures. In such circumstances, the low production well site would need to produce at or above the relevant gas sales line pressure. This may result in decreased dump frequency or duration, and therefore, reduced periods of fugitive emissions during operation. While lower operating pressure and decreased dump frequency or duration would result in lower fugitive emissions, we do not have enough information to determine the likelihood of decreased operating pressure or decreased dump frequency or duration in order to account for them in our model plant analysis.

For the reasons stated above, we are unable to conclude that semiannual monitoring is cost-effective either when it is first implemented or later when the percentage of fugitive emissions components identified with fugitive emissions declines and approaches a steady state; we, therefore, do not believe it is appropriate to retain the semiannual monitoring approach or to propose a stepped approach (which would require semiannual monitoring for an initial period). While our analysis also overestimates the cost-effectiveness of annual monitoring, any such

[35] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682 and EPA-HQ-OAR-2010-0505-7685.

overestimate would be less compared to semiannual monitoring or the stepped approach. Furthermore, as discussed earlier in this subsection and later in the storage vessels subsection, we have observed a larger than expected number of controlled storage vessels claimed to be subject to the fugitive emissions requirements in 40 CFR 60.5397a, and many of them are located at low production well sites. Available data indicates that the frequency of fugitive emissions from controlled storage vessels may be much higher than those for other fugitive emissions components.[36] In light of the above, we are proposing to change the current monitoring frequency for low production well sites from semiannual monitoring to annual monitoring.

We are soliciting comment on the annual monitoring requirement for low production well sites. Additionally, we are soliciting data on the number of major production and processing equipment (*e.g.,* separators, heater treaters, glycol dehydrators, and storage vessels) and the number of fugitive emissions components (*e.g.,* valves, open-ended lines, and connectors) located at these well sites, as well as the operating pressures of these well sites considering gas sales line pressures and the number of major production and processing equipment located at the well site (*e.g.,* separators and heater treaters). Further, the EPA is proposing that low production well sites are defined as those well sites where the average combined oil and natural gas production is less than 15 boe per day averaged over the first 30 days of production. We are soliciting comment on the definition of a low production well site, including those where all the wells located on the well site have production below 15 boe per day. We are proposing specific recordkeeping and reporting requirements in 40 CFR 60.5420a, including a requirement to describe how the well site determined it is a low production well site. We are soliciting comment on the recordkeeping and reporting requirements, including alternative information that would

[36] See TSD for additional discussion of the fugitive emissions from storage vessels.

provide the combined production of oil and natural gas for the well site. In addition to soliciting comment on the annual monitoring frequency, we are also soliciting comment and supporting data on biennial monitoring and an exemption from fugitive emissions requirements at low production well sites, for well sites both with and without controlled storage vessels.

Monitoring Frequency for Compressor Stations. The 2016 NSPS OOOOa requires initial and quarterly monitoring of the collection of fugitive emissions components located at compressor stations. The EPA is not proposing changes to the quarterly monitoring frequency requirement for the collection of fugitive emissions components located at compressor stations. As noted in section V.B.1 of this preamble, we received petitions requesting less frequent monitoring, specifically semiannual monitoring for compressor stations.[37] Similar to well sites, the EPA received information from two stakeholders regarding fugitive emissions monitoring at compressor stations.[38,39] Some of the information provided the number of fugitive emissions and percentages of fugitive emissions components identified with fugitive emissions for 110 gathering and boosting compressor stations.[40] One stakeholder asserted the data provided regarding gathering and boosting stations would support changing the monitoring frequency for compressor stations to annual monitoring. Some of this data was specific to the required monitoring of the 2016 NSPS OOOOa, while other information was specific to monitoring requirements for various state programs or consent decrees. It was difficult for us to make any conclusions from the information, except to recognize that for at least one company, the average

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[37] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682, EPA-HQ-OAR-2010-0505-7685 and EPA-HQ-OAR-2010-0505-7686.
[38] See letter from GPA Midstream Association Re: GPA Midstream OOOOa White Paper Supplemental Information, March 5, 2018, located at Docket ID No. EPA-HQ-OAR-2017-0483.
[39] See memorandum *NSPS OOOOa Monitoring Case Study Presentation by Terence Trefiak with Target Emission Services* located at Docket ID No. EPA-HQ-OAR-2017-0483. March 13, 2018.
[40] See memorandum *EPA Analysis of Compressor Station Fugitive Emissions Monitoring Data Provided by GPA Midstream* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 17, 2018.

reported initial percentage of identified fugitive emissions is almost 1.5 percent, which is higher than the 1.18 percent used for our model plant calculations. Regardless, the EPA performed a sensitivity analysis using this data to understand how the cost of control would change if we applied the data provided to compressor stations, and reached the same conclusion that quarterly monitoring is cost-effective. Additional discussion on this analysis is included in the TSD.

At this time, the EPA has not received data that supports changing the monitoring frequency to either semiannual or annual monitoring. In fact, the unique operating characteristics of compressor stations suggests quarterly monitoring, not less frequent monitoring, is more appropriate. The collection of fugitive emissions components located at compressor stations are subject to vibration and temperature cycling, which further supports more frequent monitoring. Studies indicate that components subject to vibration, high use, or temperature cycling are the most leak-prone."[41] The EPA best practices guide for LDAR states that more frequent monitoring should be implemented for components that contribute most to emissions.[42] Similarly, the Canadian Association of Petroleum Producers issued a best management practice for the management of fugitive emissions at upstream oil and gas facilities in 2007. That document states, "the equipment components most likely to leak should be screened most frequently. Additional information was also provided that suggested the operating mode of the compressor(s) located at the station was a key piece of information when detecting fugitive emissions. For instance, when compressors were in standby mode, the detected fugitive emissions were lower.[43] We had not previously considered that compressors may not be

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[41] Canadian Association of Petroleum Producers, "Best Management Practice. Management of Fugitive Emissions at Upstream Oil and Gas Facilities", January 2007.
[42] U.S. Environmental Protection Agency, "Leak Detection and Repair: A Best Practices Guide", EPA-305-D-07-001, October 2007.
[43] See memorandum *NSPS OOOOa Monitoring Case Study Presentation by Terence Trefiak with Target Emission Services* located at Docket ID No. EPA-HQ-OAR-2017-0483. March 13, 2018.

operating during the fugitive emissions survey, therefore, we are proposing that owners or operators keep a record of the operating mode of each compressor at the time of the monitoring survey, and a requirement that each compressor must be monitored at least once per calendar year when it is operating. This awareness of the impact operating mode of individual compressors may have on the occurrence of fugitive emissions further supports maintaining the quarterly monitoring frequency. For example, if the EPA moved to a semiannual or annual monitoring frequency, owners and operators may conduct fugitive emissions monitoring during scheduled maintenance periods such as the shoulder seasons, or other times when there is less demand on the station. This may artificially reflect lower fugitive emissions than if the monitoring occurred during peak seasons, thus decreasing the effectiveness of the program for controlling fugitive emissions.

For the reasons stated above, the EPA is not proposing changes to the monitoring frequency for compressor stations. The EPA is soliciting comment and information to demonstrate that emission reductions, based on the current standards, can be achieved at less frequent monitoring intervals, such as semiannual and annual monitoring. The EPA is soliciting comment on the concept of requiring less frequent monitoring after an initial 2-year period (similar to the proposal for non-low production well sites), information to demonstrate the estimated emission reductions achieved by this program, and comment on any other pathways to less frequent monitoring. Additionally, we are soliciting data in order to understand how the percentage of identified fugitive emissions may change over time; the data should include the date of construction of the compressor station, information on when the compressor station began its fugitive program, the frequency of monitoring, an indication of the location of the

compressor station, and how the surveys are performed, including the monitoring instrument used and the regulatory program followed.

The EPA is also soliciting information that can be used to evaluate if changes are necessary to the model plants. Specifically, the EPA requests information that has been collected from implementing fugitive monitoring programs. This information could demonstrate the actual equipment counts or fugitive emissions component counts at the compressor station, in relation to the number of fugitive emissions identified during each monitoring survey. Finally, the EPA solicits comment and information on costs associated with implementing a fugitive emissions monitoring program.

Well Sites and Compressor Stations Located on the Alaskan North Slope. On March 12, 2018, the EPA amended the 2016 NSPS OOOOa to include separate monitoring requirements for the collection of fugitive emissions components located at well sites located on the Alaskan North Slope.[44] As explained in that action, such separate requirements were warranted due to the area's extreme cold temperature, which is below the temperatures the monitoring instruments are designed to operate for approximately half of a year. The amended requirements for the collection of fugitive emissions components located at well sites located on the Alaskan North Slope specify that new well sites that startup production between September and March must conduct initial monitoring within 6 months of the startup of production[45] or by June 30, whichever is later, while well sites that startup production between April and August must comply with the 60-day initial monitoring requirement in the 2016 NSPS OOOOa. Similarly, well sites that are modified between September and March must conduct initial monitoring within 6 months of the first day of production for each collection of fugitive emissions

[44] 83 FR 10628.
[45] Startup of production is defined in 40 CFR 60.5430a.

components or by June 30, whichever is later. Further, all well sites located on the Alaskan North Slope that are subject to the fugitive emissions requirements must conduct annual monitoring, instead of the semiannual monitoring required for other well sites. Subsequent annual monitoring must be conducted at least 9 months apart.

Compressor stations located on the Alaskan North Slope experience the same extreme cold temperatures as the well sites located on the Alaskan North Slope. One petitioner[46] cautioned that the monitoring technology specified in the 2016 NSPS OOOOa (*i.e.*, optical gas imaging (OGI) and the instruments for Method 21) cannot reliably operate at well sites on the Alaskan North Slope for a significant portion of the year due to the lengthy period of extreme cold temperatures.[47] According to manufacturer specifications, OGI cameras, which the EPA identified in the 2016 NSPS OOOOa as the BSER for monitoring fugitive emissions at well sites, are not designed to operate at temperatures below $^{-}$ 4°F,[48] and the monitoring instruments for Method 21, which the 2016 NSPS OOOOa provides as an alternative to OGI, are not designed to operate below $^{+}$ 14°F.[49] One commenter provided data, and the EPA confirmed with its own analysis, that temperatures below 0° F are a common occurrence on the Alaskan North Slope between November and April.[50] In light of the above, there is no assurance that the initial and quarterly monitoring that must occur during that period of time are technically feasible for compressor stations located on the Alaskan North Slope. Additionally, while the 2016 NSPS

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[46] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.
[47] See Docket ID No. EPA-HQ-OAR-2010-0505-12434.
[48] See FLIR Systems, Inc. product specifications for GF300/320 model OGI cameras at *http://www.flir.com/ogi/display/?id=55671*.
[49] See Thermo Fisher Scientific product specification for TVA-2020 at *https://assets.thermofisher.com/TFS-Assets/LSG/Specification-Sheets/EPM-TVA2020.pdf*.
[50] See information on average hourly temperatures from January 2010 to January 2018 at the weather station located at Deadhorse Alpine Airstrip, Alaska. Obtained from the National Oceanic and Atmospheric Administration (NOAA)'s National Centers for Environmental Information and summarized in Docket ID No. EPA-HQ-OAR-2010-0505-12505.

OOOOa provides a waiver from one quarterly monitoring event when the average temperature is below 0° F for two consecutive months, this waiver would not fully address the issues for compressor stations located on the Alaskan North Slope. As discussed above, temperatures are below 0° F between November and April, which spans across two quarters. The low temperature wavier, only allows missing one quarterly monitoring event. Based on available information, we have concluded that semiannual monitoring is not feasible for well sites, therefore, conducting three quarterly monitoring events is likewise not feasible for compressor stations. Therefore, we are proposing amendments to the fugitive emissions requirements in the 2016 NSPS OOOOa as they apply to compressor stations located on the Alaskan North Slope.

We are proposing to establish separate fugitive monitoring requirements for compressor stations located on the Alaskan North Slope because of the technical infeasibility issues with the operations of the monitoring instruments discussed above. Similar to well sites located on the Alaskan North Slope, we are proposing that new compressor stations that startup between September and March must conduct initial monitoring within 6 months of startup, or by June 30, whichever is later. Similarly, we are proposing that modified compressor stations located on the Alaskan North Slope that become modified between September and March must conduct initial monitoring within 6 months of the modification, or by June 30, whichever is later. Compressor stations that startup or are modified between April and August would meet the 60-day initial monitoring requirement in the 2016 NSPS OOOOa. However, as discussed in section V.B.3, we are soliciting comment on extending the time frame for conducting the initial monitoring for all well site and compressor station fugitive emissions components subject to the 2016 NSPS OOOOa, including those located on the Alaskan North Slope. Further, we are proposing that all compressor stations located on the Alaskan North Slope that are subject to the fugitive emissions

requirements must conduct annual monitoring. Subsequent annual monitoring must be conducted at least 9 months apart, but no more than 13 months apart.

As discussed in section V.B.3 of this preamble (Initial Monitoring for Well Sites and Compressor Stations), the EPA is soliciting comment on whether to extend the period for conducting initial monitoring for well sites and compressor stations because additional time is needed to complete installation of equipment. For the same reason, the EPA is soliciting comment on whether to extend the time frame for initial monitoring for well sites that start up production and compressor stations that start up between April and August, and for those that are modified during this period. Further discussion on this topic is included in section V.B.3 of this preamble, which describes the concerns raised and the timeframes suggested by petitioners (180 days) and EPA (90 days) to address such concerns. In addition to the information specified in that subsection, we are soliciting comments and information specific to the well sites and compressor stations located on the Alaskan North Slope regarding allowing additional time for the initial monitoring. Upon receiving and reviewing the relevant information, the EPA may conclude that amendment to extend the timeframe for conducting the initial monitoring is necessary for all or some well site and compressor station fugitive emissions components subject to the 2016 NSPS OOOOa, including those located on the Alaskan North Slope.

One petitioner[51] requested that the EPA exempt well sites and compressor stations located on the Alaskan North Slope from fugitive emissions monitoring, similar to the exemptions from LDAR at natural gas processing plants provided in the 2012 NSPS OOOO and the 2016 NSPS OOOOa. The petitioner stated the reasons for applying an exemption to natural gas processing plants are also valid for well sites and compressor stations.

[51] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.

The EPA exempted natural gas processing plants from LDAR requirements when issuing 40 CFR part 60, subpart KKK, in 1985 (1985 NSPS KKK). At that time, we acknowledged "that there are several unique aspects to the operation of natural gas processing plants north of the Arctic Circle. Because of the unique aspects of natural gas processing plants north of the Arctic Circle, the increased costs to perform routine leak detection and repair may result in an unreasonable cost effectiveness."[52] We currently do not have sufficient information to suggest that the cost-effectiveness of the fugitive emissions requirements specific to well sites and compressor stations located on the Alaskan North Slope differ from the cost-effectiveness of the program generally. The information we do have related to the initial monitoring suggests that the average initial percentage of identified fugitive emissions for a well site located on the Alaskan North Slope is 2.38 percent.[53] Additionally, this information represents some of the highest reported percentages of identified fugitive emissions from the data set are from well sites located on the Alaskan North Slope. Therefore, we are not proposing to exempt well sites located on the Alaskan North Slope from the fugitive emissions requirements. However, we are soliciting data to support an analysis of the cost-effectiveness of fugitive emissions monitoring programs for well sites and compressor stations located on the Alaskan North Slope, including the cost associated with performing annual fugitive emissions monitoring and repairs. Specific information that distinguishes differences in cost realized by sites located on the Alaskan North Slope from our model plant estimates would be useful.

2. Modification

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[52] "Equipment Leaks of VOC in Natural Gas Production Industry – Background Information for Promulgated Standards" EPA-450/3-82-024b, May 1985.

[53] See memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 17, 2018.

Modification of Well Sites. For the purposes of fugitive emissions components at a well site, a modification is defined in 40 CFR 60.5365a(i)(3) as (i) drilling a new well at an existing well site, (ii) hydraulically fracturing a well at an existing well site, or (iii) hydraulically refracturing a well at an existing well site. As the EPA explained in that rulemaking, these three activities, which are conducted to increase production, increase fugitive emissions at well sites in two ways. First, increased production will "generate additional emissions at the well sites. Some of these additional emissions will pass through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components)." 81 FR 35881. Second, additional fugitive emissions can also result from installation of additional equipment. As the EPA observed, "it is not uncommon that an increase in production would require additional equipment and, therefore, additional fugitive emission components at the well sites." *Id.*

As previously mentioned, in a letter dated April 18, 2017, the Administrator granted reconsideration of several aspects of the 2016 NSPS OOOOa, including applying the fugitive emissions requirements at 40 CFR 60.5397a to low production well sites.[54] The petitioner who raised this issue for reconsideration identified in its petition a perceived inconsistency between the EPA's justification for not exempting low production well sites from the fugitive emissions requirements and the EPA's rationale for the definition of modification for purposes of those same requirements.[55] This petitioner observed that it appeared the EPA relied on data indicating the same equipment counts are present at all well sites, regardless of production levels, to justify regulating fugitive emissions at low production well sites, while defining modification by events that increase production *(i.e.,* drilling a new well, hydraulic fracturing, or hydraulic refracturing),

[54] See Docket ID No. EPA-HQ-OAR-2010-0505-7730.
[55] See Docket ID No. EPA-HQ-OAR-2010-0505-7685.

which the EPA concludes will increase emissions whether or not there is change in component counts. The petitioner then stated that:

> "EPA's rationale, that fugitive emissions are a function of the number and types of equipment, and not operating parameters such as pressure and volume, is inconsistent with EPA's justification for what constitutes a "modification" for an existing well site. EPA assumes that fracturing or refracturing an existing well will increase emissions because of the additional production, i.e., the additional pressure and volume. EPA cannot ignore the laws of physics to the detriment of low production wells in one instance and then "honor" them in another context to eliminate an "emissions increase" requirement in the traditional definition of "modification."[56]

In addition to the issues raised regarding an inconsistency with our treatment of fugitive emissions from low production well sites and what constitutes a modification (as discussed in section V.B.1), several petitioners stated that hydraulically refracturing a well alone would not increase emissions from the fugitive emissions components and suggested that emissions would increase from a refractured well only if additional permanent equipment is also installed.[57] According to one petitioner,

> "[a] well that is refractured typically does not require additional production equipment and does not typically operate at a pressure higher than before the refracturing since that pressure is set by the gas gathering system pressure. Therefore, as long as a significant piece of process equipment is not constructed along with the refracture, there is no emissions increase and there is no 'modification' as defined in CFR Part 60.2."[58]

In light of the above, the EPA has provided a more detailed explanation below for the definition of modification of fugitive emissions components at well sites, including how an increase in production can increase fugitive emissions at well sites even without the addition of equipment, and therefore no addition of fugitive emissions components. The EPA has also re-

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[56] See Docket ID No. EPA-HQ-OAR-2010-0505-7685, page 6.
[57] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682, EPA-HQ-OAR-2010-0505-7685 and EPA-HQ-OAR-2010-0505-7686.
[58] Docket ID No. EPA-HQ-OAR-2010-0505-7682, p. 16.

evaluated its treatment of low production well sites, which is discussed in section V.B.1 of this preamble.

There is no dispute that an addition of processing equipment, and attendant fugitive emissions components, in conjunction with refracturing a well will result in a modification. Further, as explained in the 2016 NSPS OOOOa and in more detail below, an increase in the number of components is not the sole reason for an increase in fugitive emissions when there is an increase in production.

A well is refractured for the purpose of increasing production rates. An increase in the production rate necessitates, by definition, an increase in the molar flow rate. An increase in molar flow rate can be accomplished through an increase in operating pressure (and attendant mass per unit of volume) and/or volumetric flow rate. An increase in volumetric flow rate can be accomplished through an increase to the velocity of flow, an increase to cross-sectional area of the flow path, or, if flow is intermittent, an increase to the time duration of flow (e.g., duration of flow events or frequency of flow events). Increasing velocity of flow of production fluids through process equipment can only be accomplished through an increase in the pressure drop across the system. Where increased production throughput is routed through a system of production equipment that is not physically changed, the cross-sectional area of the flow path through the equipment does not change. Therefore, the increase in production rate requires an increase to either the operating pressure and/or the duration or frequency of flow events. Where operating pressure is increased, the pressure increase will increase the molar flow rate of fugitive emissions from leaking fugitive emission components. These increased emissions on components with existing fugitive emissions will occur even if the increased operating pressure does not result in additional components with fugitive emissions at existing design stress points,

which is an additional source of potential fugitive emissions increases. Increasing duration or frequency of flow events will not be an option unless flow is intermittent. Where flow is intermittent in the process and flow event duration or frequency is increased (*e.g.*, through longer dump events or more frequent dump events), additional molar flow rate will pass through components with fugitive emissions due to increased periods of flow through that component at the same pressure. Therefore, as was stated in the 2016 NSPS OOOOa preamble language, increased production will result in "[s]ome of these additional emissions [passing] through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components)." 81 FR 35881.

There is also a third instance in which increased production from modification of a well site could cause an increase in emissions from fugitive emissions components without additional equipment, and therefore, without additional fugitive emissions components. Absent additional stages of separation or an otherwise-accomplished decrease in the pressure at the final stage of separation prior to the storage vessels, increased production throughput to storage vessels increases the flash emissions at those storage vessels. Where storage vessels are affected facilities for purposes of this rule, the rule contains separate requirements for storage vessel covers and CVS to be designed and operated to route all emissions to a control device. However, where controlled storage vessels are not affected facilities because legally and practically enforceable permits limit the potential VOC emissions to below 6 tpy, the covers and CVS are included in the fugitives monitoring program for the well site as a fugitive emissions component. In either scenario, it is possible for increased throughput to these controlled storage vessels at a well site to exceed the design capacity of the vapor control system, which may result in additional emissions from storage vessel thief hatches or other openings.

For the reasons stated above, we continue to conclude that refracturing of an existing well will increase fugitive emissions. We solicit comments on our rationale described above. Specifically, we solicit comments and data on whether emissions from fugitive emissions components will increase following a refracture if the equipment counts and operating pressures remain the same. Further, we are soliciting comments and data about how changes in production may influence the operating pressures of the well site. Additionally, we are soliciting comment and data on whether an increase in pressure alone (without additional equipment) would result in more fugitive emissions (*e.g.*, cause new fugitive emissions that were not otherwise present or would result in an increase in the fugitive emissions from an already leaking fugitive emissions component). Finally, we are soliciting comment and information on other factors, such as changes in the gas gathering system, that may influence the operating pressures of the well site.

During the implementation of the 2016 NSPS OOOOa, several questions were raised regarding the modification of a separate tank battery for the purposes of fugitive emissions monitoring. The definition of well site in 40 CFR 60.5430a states, "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)." Stakeholders have commented to the EPA that there is confusion regarding when a modification of fugitive emissions components has occurred at a separate tank battery. Similar to the information from petitioners regarding modifications without a change in equipment or component counts at a well site, stakeholders have also claimed that sending process fluids from a new well or existing hydraulically fractured or refractured well that is not located at the separate tank battery will not necessarily increase the emissions from the fugitive emissions components at the separate tank battery. Instead,

stakeholders have suggested that emissions increase only when additional processing equipment, such as storage vessels, separators, or compressors, is installed in conjunction with the additional process fluids received from these off-site wells.

The EPA agrees that clarification is warranted regarding modifications of the collection of fugitive emissions components at well sites when the well site is a separate tank battery with no wells located at the tank battery. While the regulatory text is clear about what constitutes a modification when a well is located at the separate tank battery, the regulatory text is less clear when there are no wells at the tank battery. To clarify the definition of modifications for separate tank batteries, we are proposing specific amendments to clarify when a modification occurs at a well site, including a well site that is a separate tank battery. We are proposing to amend the language in 40 CFR 60.5365a(i) to add two additional instances to clarify when there is a modification to the collection of fugitive emissions components located at a separate tank battery, such as a centralized tank battery (which itself is a well site as defined in 40 CFR 60.5430a). First, when production from a new, hydraulically fractured, or hydraulically refractured well is sent to an existing separate tank battery, the collection of fugitive emissions components at the separate tank battery has been modified. Second, when a well site that is subject to fugitive emissions requirements removes the major production and processing equipment, such that it becomes a well head only well site, and sends the production to an existing separate tank battery, the collective fugitive components at that separate tank battery has modified. In both instances, a physical or operational change occurs at an existing separate tank battery because additional production from a well site is sent to that separate tank battery, and this change results in an increase in fugitive emissions at that tank battery. We are soliciting comment on these proposed amendments to the definition of modification of the collection of

fugitive emissions components located at a well site, including the treatment of separate tank batteries as well sites for the purposes of fugitive emissions requirements.

Modification of Compressor Stations. For the purposes of fugitive emissions components at a compressor station, a modification is defined in 40 CFR 60.5365a(j) as (1) the installation of an additional compressor at an existing compressor station or (2) the replacement of one or more compressors at an existing compressor station that results in a net increase in the total horsepower to drive the compressor(s) that are replaced at the compressor station. We are not proposing any changes to this definition; however, we are soliciting comment on whether the engine horsepower is the correct measure of increased emissions from the collection of fugitive emissions components.

Further, the EPA is clarifying the type of compressors that would trigger a modification for the purposes of fugitive emissions at a compressor station. In the preamble to the 2016 NSPS OOOOa, the EPA clarified that this definition refers to instances where "the design capacity and potential emissions of the compressor station would increase." 81 FR 35864. Therefore, it is possible that the addition of a compressor would not be considered a modification where the overall design capacity of the compressor station is not increased. For example, the addition of a vapor recovery unit (VRU) compressor, such as a screw or vane compressor, would not be a modification for purposes of the compressor station fugitive emissions standards. Adding a VRU compressor does not increase the overall design capacity of the compressor station for the following reasons. VRU compressors are installed to recover methane and VOC emissions; they are not designed to "move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage." Therefore, the addition of a VRU compressor does not increase the overall design capacity of a compressor station, and does not result in a modification

of the compressor station for the purposes of fugitive emissions monitoring. The EPA is not proposing a definition for compressor in this action because we disagree that one is needed given the explanation provided above related to the definition of compressor station, and because the 2016 NSPS OOOOa already contains definitions of centrifugal and reciprocating compressors, which are the only compressor affected facilities.

3. Initial Monitoring for Well Sites and Compressor Stations

The 2016 NSPS OOOOa requires completion of initial monitoring for well sites and compressor stations by June 3, 2017 or 60 days after startup, whichever is later. For well sites, the startup of production marks the beginning of the initial monitoring survey period for the collection of fugitive emissions components at a well site. Similarly, for compressor stations, the startup of the compressor station marks the beginning of the initial monitoring survey period.

Petitioners on the 2016 NSPS OOOOa have requested that the timing of fugitive emissions initial monitoring surveys be revised to allow for integration into existing monitoring programs.[59] One petitioner asserted that there are numerous challenges to setting up and implementing a fugitive monitoring program. The petitioner reported that even with the EPA's one-year phase-in allowance, there are initial inspection timing challenges (*e.g.*, because of the significant distances between oil and gas sites). Petitioners requested that the EPA consider allowing 180 days for the initial survey. According to the petitioners, allowing for 180 days would not result in significantly more emissions and that, on average, half of the sites would likely conduct their initial survey in less than 90 days and half would likely conduct their initial survey between 90 and 180 days.

[59] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682 and EPA-HQ-OAR-2010-0505-10791.

Between proposal and promulgation of the 2016 NSPS OOOOa, several industry comments recommended a 90-day time period (in lieu of the 30-day time period we initially proposed) to complete the initial survey to (1) address time and logistical capacities of oil and gas field crews and potential limited availability of monitoring contractors, (2) be consistent with the Ohio Environmental Protection Agency's General Air Permit for Oil and Gas Well Site Production Operations (General Permit 12.2), and (3) provide a more realistic time frame to perform an initial survey without potentially resulting in safety issues while initial oil and gas production and completion activities are taking place on the well pad.[60] Other industry comments were received requesting that the EPA allow the initial fugitive survey to occur within 180 days from startup of a new well site or compressor station to (1) be consistent with similar LDAR programs, such as NSPS KKK and NSPS OOOO (where leak detection is currently imposed at natural gas processing plants), and (2) allow owners or operators time to do a thorough check of all new equipment installations before the survey.[61] One of the commenters (also a petitioner) reported that 180 days is needed to work monitoring of the new or modified well into the next scheduled monitoring period that would include all the wells in the area.[62] They asserted that hiring third-party contractors to monitor one remote well site is inefficient and costly.

We have not received data indicating that initial monitoring cannot be completed within the currently required 60-day timeframe. We continue to conclude that initial monitoring needs to be completed in a timely manner after startup of production for well sites and the startup or modification for compressor stations to verify the proper installation of equipment and that waiting 180 days for initial monitoring is too long after the installation of equipment to verify its

[60] See Docket ID Nos. EPA-HQ-OAR-2010-0505-6808, EPA-HQ-OAR-2010-0505-6935 and EPA-HQ-OAR-2010-0505-6960.
[61] See Docket ID EPA-HQ-OAR-2010-0505-6857.
[62] See Docket ID EPA-HQ-OAR-2010-0505-6884.

proper installation. However, we are soliciting data that supports or refutes the claims by the petitioner that 180 days are necessary for proper installation of equipment before conducting initial monitoring would not result in significantly more emissions. Assuming we receive information that supports extending the initial monitoring deadline to give more time for installing equipment, we think these tasks may be completed in a shorter time frame than the suggested 180 days discussed above. We are, therefore, soliciting comment and supporting data for changing the initial monitoring deadline to 90 days from 60 days after the startup of production for well sites and the startup or modification for compressor stations. Specific data would need to outline the difficulties with completing initial monitoring within the 60 days required in the 2016 NSPS OOOOa.

We recognize that the 2016 NSPS OOOOa includes a waiver from quarterly monitoring at compressor stations after recognizing there are areas of the country that may experience temperatures below 0°F for a period of 60 days. However, as discussed in detail in section V.B.4, we are not sure there are areas of the country that would utilize this waiver. The EPA is soliciting comment on how cold weather may impact the ability to comply with the 60-day initial monitoring deadline for well sites and compressor stations.

4. Low Temperature Waivers

The EPA received several petitions to reconsider the temperature-based waiver for quarterly fugitive emissions monitoring at compressor stations because this waiver was added to the 2016 NSPS OOOOa without an opportunity for notice and comment. In the 2016 NSPS OOOOa, owners and operators are granted a waiver from one quarterly monitoring event at compressor stations if the average temperature is below 0°F for two consecutive quarters. 40 CFR 60.5397a(g)(5). In the preamble to the 2016 NSPS OOOOa we stated that the waiver was

included for two reasons: (1) there were concerns raised by commenters that extreme winter weather created risk for the safety of monitoring survey personnel and (2) the manufacturer specifications indicate that OGI cameras may not reliably operate at temperatures below 0°F. 80 FR 56668.

While the petitioners supported a temperature-based waiver, they requested that EPA consider extending the waiver to well sites because sustained low temperatures can also present an issue for semiannual monitoring at well sites in some regions, specifically the Alaskan North Slope.[63] The EPA is addressing the Alaskan North Slope separately in this action. The EPA has evaluated temperature data for areas in Wyoming and North Dakota, which are areas raised by petitioners as experiencing sustained inclement weather. These data, however, does not suggest that temperatures are below 0°F for a period of time that would prohibit compliance with semiannual monitoring at well sites outside of the Alaskan North Slope.[64] Therefore, we are not proposing to extend the temperature-based waiver for semiannual monitoring at well sites. However, the EPA is soliciting data that would indicate temperatures do present a compliance concern for these well sites.

Finally, one petitioner suggested the temperature should be raised to 32°F for the waiver for two reasons: (1) the instruments for Method 21 of Appendix A-7 of Part 60 are only certified at temperatures above 32°F, and (2) there are specific concerns related to the safety of monitoring personnel.[65] Regarding the first reason, the BSER for fugitive emissions monitoring is OGI monitoring; Method 21 is provided as an alternative in case some owners and operators prefer to

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[63] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.
[64] See information on average hourly temperatures from January 2010 to January 2018 at the weather station located at Pinedale, Wyoming and Williston, North Dakota. Obtained from the National Oceanic and Atmospheric Administration (NOAA)'s National Centers for Environmental Information and summarized in Docket ID No. EPA-HQ-OAR-2017-0483.
[65] See Docket ID No. EPA-HQ-OAR-2010-0505-7686.

use it. 80 FR 56638. Manufacturer specifications on OGI cameras state that the operating range is as low as ¯ 4°F. Further, the EPA has examined manufacturer specifications for Method 21 instruments and found that newer models of the toxic vapor analyzer are designed for operating temperatures above 14°F.[66] Regarding the second reason, while worker safety was raised as an issue, the petitioner did not provide specific data to allow the EPA to evaluate a change to the waiver based on worker safety. We are soliciting additional data that would support different temperature-based waivers for monitoring at compressor stations.

5. Repair Requirements

Repair. After detection of fugitive emissions, the 2016 NSPS OOOOa requires repair of these components within 30 days of detection of the fugitive emissions. Further, the owner or operator must resurvey the component within 30 days of the repair in order to verify successful repair. 40 CFR 60.5397a(h)(1) and (3).

Several questions were raised during implementation that required reconsideration of the repair requirements. Specifically, stakeholders asked about the situation where repairs were completed during the 30-day required timeframe but the resurvey identified the presence of fugitive emissions, indicating unsuccessful repair.

The EPA recognizes the requirements in the 2016 NSPS OOOOa may create an unintended noncompliance issue with the repair requirements. Therefore, we are proposing to amend the repair requirements to require a "first attempt at repair" within 30 days of detection of fugitive emissions, followed by a requirement that identified fugitive emissions be "repaired" within 60 days of detection. We are proposing definitions for "repaired" and "first attempt at repair" as related to the fugitive emissions requirements. The EPA is proposing to define

[66] See Thermo Fisher Scientific product specification for TVA-2020 at https://assets.thermofisher.com/TFS-Assets/LSG/Specification-Sheets/EPM-TVA2020.pdf.

"repaired," for purposes of fugitive emissions monitoring, as "fugitive emissions components are adjusted, replaced, or otherwise altered, in order to eliminate fugitive emissions as defined in 40 CFR 60.5397a of this subpart and is resurveyed as specified in 40 CFR 60.5397a(h)(4) and it is verified that emissions from the fugitive emissions components are below the applicable fugitive emissions definition." Additionally, we are proposing the definition for "first attempt at repair" for the purposes of fugitive emissions monitoring as "an action taken for the purpose of stopping or reducing fugitive emissions of methane or VOC 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; ensuring the thief hatch is properly seated or injecting lubricant into lubricated packing." These proposed definitions for "repaired" and "first attempt at repair" are specific to the fugitive emissions requirements and would not replace the definitions for "repaired" or "first attempt at repair" within the requirements for equipment leaks at onshore natural gas processing plants referenced in 40 CFR part 60, subpart VVa. We are soliciting comment on these proposed repair requirements and definitions.

Delay of Repair. As amended on March 12, 2018, the 2016 NSPS OOOOa allows for delay of repair if the repair is technically infeasible; requires 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. Repairs meeting one of these criteria must be completed during the next scheduled compressor station shutdown, well shutdown, or well shut-in; after a planned vent blowdown; or within 2 years, whichever is earlier. The amendment addressed the concerns associated with requiring repair during unscheduled or emergency events by removing such a requirement.

In addition to concerns with requiring repair during unscheduled or emergency events, several petitioners raised additional concerns with the provisions regarding the delay of repair for fugitive emissions components at well sites and compressor stations.[67] One petitioner stated that the 2-year delay should be reevaluated because no specific data was provided to support that deadline.[68] Further, other petitioners stated that blowdowns, shutdowns, and well shut-ins might not always involve depressurizing the specific equipment that needs repair. The EPA is soliciting comment on instances when equipment cannot be isolated during vent blowdowns, compressor station shutdowns, well shutdowns, and well shut-ins to allow for repair of components with fugitive emissions. Further, the EPA is soliciting comment and supporting information on the instances where delayed repairs cannot be conducted during any of the events listed in the rule and under what event or time frame delayed repairs can be conducted for those instances.

Finally, we are clarifying when a repair can be delayed. There are three circumstances when repair can be delayed: (1) when the repair is technically infeasible, (2) when the repair requires a vent blowdown, a compressor station shutdown, a well shut-in, or a well shutdown, and (3) when the repair is unsafe during operation of the unit.[69] The 2016 NSPS OOOOa requires an explanation of each repair that is delayed as well.[70] As discussed in section V.B.1, we have added 1 controlled storage vessel per model plant because when the controlled storage vessel is not subject to the control requirements in 40 CFR 60.5395a, the thief hatch and other openings are subject to fugitive emissions requirements, per the definition of fugitive emissions components in 40 CFR 60.5430a. The EPA believes that thief hatches on controlled storage

[67] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682, EPA-HQ-OAR-2010-0505-7683, and EPA-HQ-OAR-2010-0505-7686.
[68] See Docket ID No. EPA-HQ-OAR-2010-0505-7683.
[69] See 40 CFR 60.5397a(h)(2).
[70] See 40 CFR 60.5420a(b)(7)(ii)(J).

vessels which are part of the fugitive emissions program would not be subject to delay of repair under any of these circumstances; however, we are soliciting comment for any instance when delaying repair on a thief hatch may be necessary. We are concerned that questions may arise as to whether opening a thief hatch is considered a vent blowdown. While we do not consider this to constitute a vent blowdown, we are soliciting comment on whether clarification within the regulatory text is necessary for this point. We are also soliciting comment on the 2-year deadline for completion of delayed repairs.

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

Third-party equipment. In the 2016 NSPS OOOOa, all fugitive emissions components located at a well site, regardless of ownership, are subject to the monitoring and repair requirements for fugitive emissions in the 2016 NSPS OOOOa. As defined in 40 CFR 60.5430a, the term 'fugitive emissions component' means "any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including, but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411a, thief hatches or other openings on a controlled storage vessel not subject to §60.5395a, compressors, instruments, and meters" and the term '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." Several petitioners raised concerns that these definitions are too broad and requested that the EPA should exclude equipment that is owned and operated by a third-party.[71]

First, petitioners requested an exemption for equipment owned and operated by midstream companies because that equipment is owned by legally distinct entities, and

[71] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682 and EPA-HQ-OAR-2010-0505-7684.

applicability of the standards to midstream assets would be based solely on the actions of the upstream producers. Second, petitioners stated that the EPA is incorrect in suggesting that contractual agreements between upstream producers and midstream owners and operators would be appropriate for managing fugitive emissions monitoring and repair(s) at the well site. The petitioners stated that, due to the complexity of contractual agreements between different owners and operators at a well site, each individual owner or operator may need to develop and implement separate fugitive emissions monitoring programs. The petitioner further stated that doing so would add significant and unnecessary costs that the EPA did not consider.[72]

In the response to comment document for the 2016 NSPS OOOOa we stated that cooperative agreements could be used to resolve any fugitive emissions identified during surveys, but we acknowledged in the 2017 NODA that confusion remained over the applicability of the fugitive emissions requirements as they relate to ancillary midstream assets that are owned by legally distinct companies from the well site owner and operator and could have limited emissions. 82 FR 51798. In their comments on the 2017 NODA, one petitioner noted that since the components associated with the gas gathering and metering systems serve the "crucial commercial purpose in calculating gas accepted by the gathering company and the related revenue accounting", the midstream operators could not allow the production operators to access this equipment.[73] This petitioner further clarified that due to this limitation, the midstream operator would need to implement a separate fugitive emissions program for a limited number of components. Additionally, the petitioner stated there are significant practical issues with renegotiating contracts, especially as well sites are modified over time. We did not consider this issue during development of the 2016 NSPS OOOOa.

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[72] See Docket ID No. EPA-HQ-OAR-2010-0505-7684.
[73] See Docket ID No. EPA-HQ-OAR-2010-0505-13436.

In light of the concerns raised by the petitioners, the EPA is proposing to amend the definition of "well site", for the purposes of fugitive emissions monitoring, to exclude the flange upstream of the custody meter assembly, and fugitive emissions components located downstream of this flange. The EPA understands this custody meter is used effectively as the cash register for the well site and provides a clear separation for the equipment associated with production of the well site, and the equipment associated with putting the gas into the gas gathering system. Additionally, the proposed definition would exclude only a small number of fugitive emissions components, and we do not believe it would be cost-effective to require a separate fugitive emissions program for these components. We are also proposing a definition for the 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." We are limiting the exemption within the definition of a well site to the flange upstream of the custody meter because we are not aware of similar issues with monitoring other third-party equipment at a well site. The EPA is soliciting comment on this proposed change to the "well site" definition, the proposed definition of "custody meter", the proposed definition of "custody meter assembly", and suggestions for other ways which provide a clear separation to distinguish the third-party equipment described above at a well site, for the purposes of fugitive emissions monitoring.

Applicability to Saltwater Disposal Wells. In addition to concerns about the definition of a "well site" as it relates to third party equipment, the EPA received feedback from industry seeking confirmation that a saltwater disposal well is not an injection well as the term is used in the definition for well site and, therefore, not subject to the fugitive emission standards at 40

CFR 60.5397a. They asserted that disposal wells are not injection wells and that the disposed liquid consists of water with insignificant amounts of stabilized skim oil that is never in vapor state at normal or elevated conditions. The commenters were concerned that, although they did not believe it was the EPA's intent to require fugitive emissions monitoring of saltwater disposal wells, they will nevertheless have to comply with those requirements because, as written, the definition of "well site" is ambiguous with respect to the status of saltwater disposal wells.

Deposits of oil and natural gas can be found in porous rocks and shale, where saltwater is also found. Oil and gas pumped out of the earth that is not pure enough for distribution because of saltwater and other chemicals/impurities go through a separation phase or are treated with chemicals that extract the impurities. After the oil or gas is treated, the water that remains (referred to as "saltwater") is subject to handling requirements.[74] Saltwater, or produced water, that results from bringing the oil and gas up to the surface (ejected from the well) during production operations is generally (1) recycled, (2) returned to the reservoir for fluid reinjection or (3) injected into underground porous rock formations not productive of oil or gas, and sealed above and below by unbroken, impermeable strata.[75] The third option is considered saltwater disposal (or oilfield wastewater disposal). Regulations for the disposal of this water vary from state to state, but the EPA monitors disposal to ensure ground water is not contaminated through Underground Injection Control (UIC) programs under the federal Safe Drinking Water Act for surface and groundwater protection. The EPA had not considered these UIC Class II oilfield wastewater disposal wells during the development of the fugitive emissions standards in the 2016 NSPS OOOOa.

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[74] http://www.tech-flo.net/salt-water-disposal.html.
[75] Barnett Shale Energy Education Council. *What are Saltwater Disposal Wells*? Air and Water Quality. http://www.bseec.org/what_are_saltwater_disposal_wells.

For the reasons stated below, we are proposing to exclude UIC Class II oilfield wastewater disposal wells from the well site definition and are proposing a definition for a UIC Class II oilfield wastewater disposal well to distinguish them from injection wells subject to the rule. It is our understanding that the storage vessels located at these disposal facilities have low methane and VOC emissions, and thus are not subject to the control requirements for storage vessels found in 40 CFR 60.5395a, do not require controls for permitting purposes, and would not be subject to fugitive emissions monitoring because they are uncontrolled. Further, it is our understanding that the number of fugitive emissions components at these facilities are typically low, including water pumps and a limited number of valves or connectors, which are expected to have negligible if any fugitive emissions. These proposed changes clarify the universe of well sites subject to the fugitive emissions standards. Our proposed definition for a "UIC Class II oilfield 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." Further, we are proposing that 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. We are soliciting comment on this proposed definition and on the proposed exemption for UIC Class II wastewater disposal wells and disposal facilities from fugitive emissions monitoring and repair, including data to support or refute our understanding that these sites have limited fugitive emissions components.

Definition of well site. As discussed in the sections regarding third-party equipment and saltwater disposal wells, the EPA is proposing to amend the definition of well site as follows:

> *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

fugitive emission standards at §60.5397a, a well site also means a separate tank battery surface site collection 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 and (2) the flange upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.

Startup of Production. The EPA defines the "startup of production" in the 2016 NSPS OOOOa 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." 40 CFR 60.5430a. For purposes of the fugitive emissions requirements in 40 CFR 60.5397a, the initial monitoring survey follows the startup of production. We received questions from stakeholders that suggested this definition would limit the fugitive emissions requirements to well sites with hydraulically fractured wells and not those with conventional wells. While the first trigger for modification is based on the drilling of a new well, regardless if it is hydraulically fractured or not, the definition of startup of production is linked to flowback, which is inherently an effect following hydraulic fracturing.

We are proposing to amend the definition of "startup of production" in this proposal to address how it relates to the fugitive emissions requirements. Specifically, we are proposing that, for the purposes of the fugitive monitoring requirements, 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." We are soliciting comment on this proposed definition change as it relates to wells that are not hydraulically fractured.

7. Closed Vent Systems (CVS) and Storage Vessel Thief Hatches

The requirements for CVS are specific to the type of affected facility that is associated with the CVS (*i.e.*, "routes to" the CVS). CVS receiving emissions from centrifugal compressor,

reciprocating compressor, and pneumatic pump affected facilities must be (a) initially and annually inspected visually for defects and (b) initially and annually monitored using Method 21 to verify operation at no detectable emissions (*i.e.*, an instrument reading less than 500 parts per million (ppm) above background concentration). In contrast, no instrument monitoring is required for CVS receiving emissions from storage vessel affected facilities and monthly auditory, visual, and olfactory (AVO) inspections must be performed. 40 CFR 60.5416a. Several petitioners have stated that the requirements for CVS associated with pneumatic pumps should be aligned with the requirements for CVS associated with storage vessels instead of the CVS requirements for centrifugal or reciprocating compressors.[76] In addition, these petitioners stated, though incorrectly, that pneumatic pumps are subject to OGI monitoring under the fugitive emissions requirements as well as the annual Method 21 requirement; the petitioners, therefore, assert that the Method 21 requirement is duplicative and burdensome. Pneumatic pumps are not fugitive emissions components because they vent as part of normal operation. Finally, stakeholders have requested streamlined and standardized requirements for all CVS, in place of equipment-specific requirements currently in the 2016 NSPS OOOOa. Specifically, the requirements are spread over multiple sections of the rule and vary based on the affected facility associated with the CVS as stated above, which the stakeholders have indicated creates confusion regarding compliance.

The EPA has received information from various stakeholders that overlapping requirements for these CVS and openings on controlled storage vessels may still exist due to state program requirements. Specifically, two stakeholders have informed us they are required to perform quarterly OGI monitoring on the CVS located at well sites under their state program in

[76] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682, EPA-HQ-OAR-2010-0505-7685 and EPA-HQ-OAR-2010-0505-7686.

addition to the annual Method 21 requirement on the same CVS for their affected facility pneumatic pumps as required by the 2016 NSPS OOOOa. We agree with the stakeholders that amendments are appropriate for the CVS requirements for pneumatic pumps

We are proposing to align the CVS monitoring requirements for affected facility pneumatic pumps with the CVS monitoring requirements for affected facility storage vessels. As stated by the petitioners, we agree that pneumatic pumps and storage vessels are commonly located at well sites and agree that having separate monitoring requirements for potentially shared CVS is overly burdensome and duplicative. This proposed amendment effectively requires monthly AVO monitoring for the CVS located at well sites because there are no affected facility reciprocating or centrifugal compressors located at well sites. We are soliciting comment on this proposed amendment for CVS on affected facility pneumatic pumps. Additionally, we are soliciting comment on other methods that could be employed as an alternative to the monthly AVO monitoring to ensure the CVS is operated with no detectable emissions. Finally, we are not proposing any changes to the CVS requirements for affected facility centrifugal compressors or reciprocating compressors.

8. Fugitive Emissions Monitoring Plan

The 2016 NSPS OOOOa requires that each fugitive emissions monitoring plan include a sitemap and a defined observation path.[77] As we are clarifying in this proposed action, these requirements were meant to apply only to owners and operators using OGI for monitoring surveys, not to owners and operators using Method 21. In addition to clarifying this intent, we are also proposing options that owners and operators using OGI for monitoring surveys can comply with in lieu of the observation path requirement.

[77] See 40 CFR 60.5397a(d)(1) and (2).

As we discussed in the preamble to the 2016 NSPS OOOOa, the purpose of the observation path is to ensure that the OGI operator visualizes all of the components that must be monitored. In a traditional monitoring scenario using Method 21, the owner or operator tags all of the equipment that must be monitored, and when the operator subsequently inspects the affected facility, the operator scans each component's tag and notes the component's instrument reading. The EPA realizes that this is a time-consuming practice that requires close contact with each component, whereas with OGI, the operator can be away from the components and still monitor several components simultaneously. The observation path[78] was intended to offer owners and operators an alternative to the traditional tagging approach while still providing assurance that the owner or operator has met the obligation to monitor all components. 81 FR 35860.

Petitions received on the 2016 NSPS OOOOa assert that there is no added benefit to including the sitemap and defined observation path in the fugitive emissions monitoring plan and that they should be removed.[79] Industry representatives report that, in many cases, sitemaps do not exist. They further report that there are significant added costs associated with the requirement to develop site-specific details for a sitemap and a defined observation path for each site and that there may be hundreds to thousands of different sites. These representatives express concern that sitemaps could also change, subjecting them to additional costs associated with revising the fugitive emissions monitoring plan without any added benefit. While we do think

[78] In the preamble to the 2016 NSPS OOOOa, we also noted that the purpose of using the term "observation path" was to clarify that the emphasis is on the field of view of the OGI instrument, not the physical location of the OGI operator. 81 FR 35860.
[79] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7686 and EPA-HQ-OAR-2010-0505-10791.

that it is necessary to revise monitoring plans when equipment at the site changes,[80] we generally expected these to be one-time requirements, unless additional equipment is added to the site. 81 FR 35860. The EPA is specifically seeking comment on whether this assumption is incorrect and, if not, we solicit information on the cost to develop and revise the sitemap, including the cost to document an observation path, the cost to revise a sitemap and observation path, and the frequency with which the sitemap and observation path need to be updated. We are also clarifying that plot plans can be substituted for sitemaps, as these two items serve the same function, *i.e.,* to provide information on the locations of equipment on site.

Industry representatives have also expressed concern that the fugitive emissions monitoring plan as written in 40 CFR 60.5397a(d) may cause enforcement issues in cases where the fugitive emissions monitoring plan is not followed exactly (specifically related to the defined observation path), even when the deviation is not critical and the monitoring plan is still effective. In response to public comments on the 2016 NSPS OOOOa, we stated that the elements required in the monitoring plan are necessary to judge the quality of the fugitive emissions survey, in light of the fact that the EPA does not have a standard method for use of OGI, but that we fully expected a trained and experienced camera operator to know when deviations from the standard monitoring plan are necessary and to make these deviations.[81] However, while deviations may not impact the camera's detection ability and can actually improve the detection ability, this does not mean that deviations from the monitoring plan should not be noted because this record provides valuable information to air agency reviewers on how

[80] As we stated in the preamble to the 2016 NSPS OOOOa, we do not expect facilities to create overly detailed process and instrumentation diagrams to describe the observation path. The observation path description could be a simple schematic diagram of the facility site or an aerial photograph of the facility site, as long as such a photograph clearly shows locations of the components and the OGI operator's walking path. 81 FR 35860

[81] See Docket ID No. EPA-HQ-OAR-2010-0505-7632, Chapter 4, page 4-708.

surveys are conducted and whether the deviations from the monitoring plan are adequate and warranted. We note that deviations from the monitoring plan are not necessarily deviations from the requirements of the rule.

While we are not proposing to remove the sitemap and observation path elements from the fugitive emissions monitoring plan, we are proposing two alternatives to address petitioner/industry representative concerns. First, in lieu of the defined observation path, we are proposing to add language to 40 CFR 60.5397a(d) that allows an owner or operator to describe how each type of equipment will be effectively monitored, including a description and location of the fugitive emissions components located on the equipment. The sitemap would include the locations of the pieces of equipment when complying with this option. Second, in lieu of meeting the sitemap and defined observation path requirements, we are proposing to add language to 40 CFR 60.5397a(d) to extend the inventory requirement that is currently in 40 CFR 60.5397a(d)(3) for when an owner or operator chooses to perform a survey with Method 21 as an option for owners and operators who perform surveys with OGI. We believe that both of these options provide assurances similar to the observation path that the owner or operator meets the requirement to visualize all components.

In summary, the EPA is retaining the requirements for the sitemap and observation path in the fugitive monitoring plan, but is also proposing two alternatives to these requirements. The EPA is soliciting comment on these proposed alternatives. Additionally, we are soliciting comment on other potential options that would serve the same functions as an observation path and sitemap. We are particularly interested in potential options that provide assurance that all regulated components have been monitored, how this information can be documented, and the costs of such alternative approaches.

C. Professional Engineer Certifications

The 2016 NSPS OOOOa requires that CVS used for routing emissions from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps, and storage vessels must have sufficient design and capacity to ensure that all emissions are routed to the control device. 40 CFR 60.5411a(d). This is accomplished through a design evaluation that must be certified by a "qualified professional engineer" (PE). Several petitioners requested reconsideration of the PE certification requirement because the EPA did not provide an evaluation of the costs associated with the certification.[82] Additionally, petitioners requested that the EPA allow alternatives to PE certification, such as engineering design reviews not necessarily conducted by a licensed PE.

The 2016 NSPS OOOOa also includes a technical infeasibility provision from the well site pneumatic pump requirements. However, the rule requires that such technical infeasibility be determined and certified by a "qualified professional engineer". 40 CFR 60.5393a(b)(5)(i). Petitioners objected to this additional certification, stating it results in additional costs and project delays, with no environmental benefits. Additionally, petitioners questioned the value of this requirement, claiming it is duplicative with the existing general duty obligations and certifying official's acknowledgment. Petitioners also stated that few companies have a sufficient number of in-house PEs, and requested that this requirement be broadened to allow alternatives to PE certification, including requiring engineering review and approval of all designs.

In the 2017 NODA, we requested information related to the availability of PEs to provide these certifications. Seven commenters provided information. Three commenters stated that there should be no limitation related to the availability of licensed PEs because in 2016 over 400,000

[82] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682, EPA-HQ-OAR-2010-0505-7685 and EPA-HQ-OAR-2010-0505-7686.

resident licenses were issued, and over 400,000 non-resident licenses were issued (a PE can hold both types of licenses).[83] One commenter cited a similar requirement in Colorado's regulation and stated that in response to the same concerns from the industry, Colorado found there was no basis for the claims about a lack of availability of PEs.[84] In contrast, four commenters stated difficulties with locating a PE willing to provide the certification, citing multiple concerns, including the certification statement included in the 2016 NSPS OOOOa and the certification of a portion of a system when the PE did not design the entire system.[85]

We have evaluated the concerns raised by petitioners regarding the additional burden of the PE certification for CVS design and pneumatic pump technical infeasibility. Further, the EPA agrees with commenters that in-house engineers may be more knowledgeable about site design and operation for both CVS and pneumatic pumps. In addition, the EPA acknowledges that, in the 2016 NSPS OOOOa, we had not analyzed the costs associated with the PE certification requirement and evaluated whether the improved environmental performance this requirement may achieve justifies the associated costs and other compliance burden. In this action, the EPA evaluated the costs associated with PE certification and certification by an in-house engineer. We estimated costs based on two scenarios: (1) requiring a PE certify the design and (2) allowing either a PE or an in-house engineer certify the design. We estimate that each PE certification would cost $547, while allowing use of in-house engineers would cost $358.[86] The EPA is soliciting comment on this cost estimate.

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[83] See Docket ID Nos. EPA-HQ-OAR-2010-0505-12386, EPA-HQ-OAR-2010-0505-12441, and EPA-HQ-OAR-2010-0505-12469.
[84] See Docket ID No. EPA-HQ-OAR-2010-0505-12469.
[85] See Docket ID Nos. EPA-HQ-OAR-2010-0505-12422, EPA-HQ-OAR-2010-0505-12424, EPA-HQ-OAR-2010-0505-12437, and EPA-HQ-OAR-2010-0505-12446.
[86] See the TSD for additional discussion of certification cost.

After reconsideration of these costs, the EPA is proposing to amend the certification requirements for CVS design and technical infeasibility for pneumatic pumps. Specifically, we are proposing to allow certification by either a PE or an in-house engineer with expertise on the design and operation of the CVS or pneumatic pump. We believe that an in-house engineer with knowledge of the design and operation of the CVS is capable of performing these certifications, regardless of licensure; however, we are soliciting comment on the use of other engineers with knowledge of the design and operation of the CVS that may be appropriate for this certification, such as third-party engineers. We continue to have a concern regarding the use of undersized or under designed CVS, which can result in pressure relief events from thief hatches and PRVs on the controlled storage vessels or CVS, thus allowing emissions to escape to the atmosphere uncontrolled. As stated in the 2013 NSPS OOOO Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards, "Improper design or operation of the storage vessel and its control system can result in occurrences where peak flow overwhelms the storage vessel and its capture systems, resulting in emissions that do not reach the control device, effectively reducing the control efficiency. We believe that it is essential that operators employ properly designed, sized, and operated storage vessels to achieve effective emissions control." 78 FR 22136. This proposed amendment will still ensure these systems are evaluated and certified by engineers with expert knowledge of their operation.

D. Alternative Means of Emission Limitation (AMEL)

The 2016 NSPS OOOOa contains provisions for owners and operators to request an AMEL for specific work practice standards in the rule, covering well completions, reciprocating compressors, and the collection of fugitive emissions components at well sites and compressor stations. An owner or operator can request an AMEL by submitting data that demonstrate the

alternative will achieve at least equivalent emission reductions as the requirements in the rule, among other requirements such as initial and on-going compliance monitoring. The specific requirements for this request are outlined in 40 CFR 60.5398a. For the 2016 NSPS OOOOa, these alternatives could be based on emerging technologies (*e.g.*, for fugitive emissions, technologies other than OGI or Method 21) or requirements under state or local programs.

We are proposing to amend the language in 40 CFR 60.5398a for incorporation of emerging technologies, and adding a separate section at 40 CFR 60.5399a to take into account existing state programs as discussed in further detail in the sections below.

1. Incorporating Emerging Technologies

As discussed in the 2016 NSPS OOOOa, the EPA recognizes that new technologies are expected to enter the market in the near future that will locate the source of emissions sooner and at lower levels than current technology. While the EPA established a foundation for approving the use of emerging technologies in the final rule, several stakeholders have identified a need to streamline the process for requesting and approving an AMEL for individual affected sources, such as well completions, compressors, and the collection of fugitive emissions components located at a well site or at a compressor station. As promulgated in the 2016 NSPS OOOOa, each AMEL request must be submitted using site-specific information, which could result in the same owner or operator submitting identical requests for multiple affected facilities. We are clarifying that an individual application may include the same technology for multiple sites, provided the required information is provided for each site and site-specific variations to the procedures are addressed in the application. The application must provide a demonstration of equivalency and the emission reductions achieved for each site included in the application. The EPA is also proposing specific changes to the AMEL process as it relates to emerging technologies to

address this issue. Specifically, we are proposing to allow owners or operators to apply for an AMEL, on their own or in conjunction with manufacturers or vendors, and trade associations, that incorporates the use of alternative technologies, techniques, or processes, along with compliance monitoring provisions to ensure continuous compliance other than those identified in the 2016 NSPS OOOOa work practice standards. We are not changing the requirement that AMELs must be site-specific because we are aware of the variability of this sector and are concerned that the procedures for a specific technology may need to be adjusted based on site-specific conditions (*e.g.,* gas compositions, allowable emissions, or landscape). Therefore, we expect that applications for these AMEL will include site-specific procedures for ensuring continuous compliance of the emission reductions to be demonstrated as equivalent. For this reason, we are not proposing to allow a manufacturer, vendor, or trade association to apply for an AMEL without an owner or operator. Additionally, we are proposing that field data can be supplemented with test data, modeling analyses and other documentation, provided the field data still provides information related to seasonal variations. For the purposes of fugitive emissions requirements, the application must demonstrate that the technology is able to detect emissions beyond those allowed, such as pneumatic controllers. We are soliciting comment on the proposed revisions to the application requirements for technology-based AMEL.

2. Incorporating State Programs

In addition to recognizing potential emerging technologies, the EPA evaluated existing state and local fugitive emissions programs during the development of the 2016 NSPS OOOOa for purposes of establishing AMEL. The EPA was unable to conclude that any state program as a whole would reflect what we identified as BSER in the 2016 NSPS OOOOa due to the differences in the sources covered and the specific requirements. However, the 2016 NSPS

OOOOa allowed owners and operators to use the AMEL process to allow use of existing state or local programs. 81 FR 35871. Petitioners and states have raised specific questions about the practicality of the AMEL process as it relates to the incorporation of state programs.[87] For instance, one state has notified the EPA that since the ability to make an AMEL request is limited to owners and operators at the individual site level, it is possible that the EPA would have over 300 identical applications from various owners and operators wanting to use the same state program at their affected facilities. Believing that there may be opportunities to streamline the process, ensure compliance, and reduce regulatory burdens, the EPA continued its evaluation of existing state fugitive emissions programs after promulgating the 2016 NSPS OOOOa. Based on this evaluation, the EPA is proposing certain existing state requirements as alternatives to specified aspects (*e.g.*, monitoring, repair, and recordkeeping) of the fugitive emissions requirements for well sites and compressor stations.

To date, the EPA has evaluated 14 existing state programs for comparable or equivalent standards related to the fugitive emissions requirements in 40 CFR 60.5397a and the specific amendments in this proposal. For this evaluation, we compared the fugitive emissions components covered by the state programs, monitoring instruments, leak or fugitive emissions definitions, monitoring frequencies, repair requirements, and recordkeeping to the fugitive emissions requirements proposed in this action.[88] We did not include an evaluation of monitoring plans or reporting requirements because we are not proposing any alternative standards for these aspects of the fugitive emissions requirements. Through this evaluation, we have identified

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[87] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682, EPA-HQ-OAR-2010-0505-7685 and EPA-HQ-OAR-2010-0505-7686.

[88] See memorandum *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 12, 2018.

aspects of certain existing state fugitive emissions programs that we find to be at least equivalent to the proposed amendments in this action.[89] For instance, we have evaluated the lists of affected fugitive components, monitoring instrument(s), fugitive definition(s), monitoring frequency, repair deadlines, delay of repair provisions, and recordkeeping of the programs reviewed. In most of the programs, the affected fugitive components were different than our definition of fugitive emissions component, therefore, we are proposing alternative standards that also require the owner or operator to survey our entire list of fugitive emissions components, regardless of whether they are affected components in the state program. Additionally, we evaluated monitoring instruments, frequencies, and fugitive definitions in conjunction with each other. Where monitoring is more frequent, we are proposing that a different fugitive definition could be appropriate. For instance, the standards in the California Code of Regulations, title 17, sections 95665-95667 require quarterly monitoring using Method 21 with a fugitive definition of 1,000 ppm while this proposal requires annual or stepped monitoring with a fugitive definition of 500 ppm if Method 21 is the chosen monitoring instrument. The EPA believes that more frequent monitoring warrants allowance of a higher fugitive definition because larger fugitive emissions will be found faster and repaired sooner, thus reducing the overall length of the emission event. Additional information related to the specific evaluation of programs is available in the memorandum *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa*, located at Docket ID No. EPA-HQ-OAR-2017-0483.

Based on this evaluation, we are proposing combining those aspects of the state requirements to formulate alternatives to the relevant portions of the fugitive emissions standards

[89] California, Colorado, Ohio, Pennsylvania, Texas, and Utah.

for the collection of fugitive emissions components located at either well sites or compressor stations. The specific states for which we are proposing alternative standards are California, Colorado, Ohio, and Pennsylvania for both well sites and compressor stations, and Texas and Utah for well sites only. We have not determined whether Pennsylvania's Exemption No. 38 for well sites should be included in the alternative standards, and we are soliciting comment on whether a state would revert to its original program once the monitoring frequency for well sites is reduced. While we evaluated the current consent decree[90] that the state of North Dakota has developed for well sites, we are not proposing alternative standards related to those requirements because by their nature, consent decrees are negotiated terms for non-compliance and contain an expiration date, after which sources return to compliance with the underlying regulatory provisions, permit terms, etc. Further, inclusion of settlement terms from a consent decree as an alternative standard would essentially endorse regulation through enforcement as a pathway to establishment of alternative standards. For all of these reasons, the EPA believes that evaluation of settlement agreement terms reached through negotiated resolution to an enforcement action would be an inappropriate basis from which to establish alternative standards for regulations promulgated through notice and comment rulemaking. Additionally, we are identifying the specific effective date of the individual state programs to specify which version of the state programs is being proposed as alternative standards because the state programs may change over time, and our evaluation is only valid for the current version of these programs. If in the future any of these programs are amended, the states can utilize the proposed application procedure discussed below.

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[90] See North Dakota Consent Decree 10.19.16, attachment to the memorandum *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa*. April 12, 2018, in Docket ID No. EPA-HQ-OAR-2017-0483.

The proposed alternative fugitive emissions standards include alternatives for monitoring frequencies, repair deadlines, and recordkeeping. The requirements for the monitoring plan found in 40 CFR 60.5397a(c) and (d) would still apply. In fact, the owner or operator would indicate through this monitoring plan that they have elected the alternative and would base the monitoring plan on the specific requirements from the state, local, or tribal program that is being adopted. Compliance would be evaluated against the specified requirements in the alternative fugitive emissions standards as incorporated in the monitoring plan. Further, we are proposing to require notification that the owner or operator has elected to comply with the applicable alternative fugitive emissions standards for the state in which the well site or compressor station is located. We are proposing that this notification is made at least 90 days prior to adopting an alternative fugitive emissions standard. We are soliciting comment on this notification requirement, including the appropriateness of the use of 90 days prior to adoption of the alternative standards.

In this action we are proposing a new section, in proposed 40 CFR 60.5399a, to include these state requirements that qualify as alternative fugitive emissions standards. The proposed section also includes a framework for the application and inclusion of additional existing state fugitive emissions standards as alternatives to the fugitive emissions requirements or future revisions to programs already proposed as alternative standards. Under our proposal, such applicants would include, but not be limited to, individuals, corporations, partnerships, associations, states, or municipalities. The proposed requirements for the application include specific information about the monitoring instrument (including monitoring procedures), monitoring frequency, leak or fugitive emissions definition, and repair requirements. We are soliciting comment on the proposed application requirements, the proposed alternative fugitive

emissions standards (including compliance monitoring), and information to support the inclusion of additional alternative fugitive emissions standards.

E. Other Reconsideration Issues Being Addressed

1. Well Completions

Location of a Separator During Flowback. The 2016 NSPS OOOOa requires the owner or operator to have a separator onsite during the entirety of the flowback period. 40 CFR 60.5375a(a)(1)(iii). However, several petitioners indicated that it is not clear whether the term "onsite" refers to the specific well site where the well completion is taking place.[91] Our intent was that the separator be located in close enough proximity to the well that it could be utilized as soon as sufficient flowback is present for the separator to function. Close proximity could be either onsite or nearby, as we explained in the preamble to the 2016 NSPS OOOOa, "We anticipate a subcategory 1 well to be producing or near other producing wells. We therefore anticipate REC equipment (including separators) to be onsite or nearby, or that any separator brought onsite or nearby can be put to use." 81 FR 35852. Thus, our intent was that the separator may be located at the well site or near to the well site so that it is able to commence separation flowback, as required by the rule. Locations "near" or "nearby" may include a centralized facility or well pad that services the well which is used to conduct the completion of the well affected facility. In order to alleviate concerns that the separator must be located on the well site, we are proposing to amend 40 CFR 60.5375a(a)(1)(iii) to clarify the location of the separator.

Screenouts and Coil Tubing Cleanouts. Petitioners requested clarification as to whether screenouts and coil tubing cleanouts are regulated as part of flowback. Petitioners asserted that these are necessary processes performed during hydraulic fracturing that are not associated with

[91] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682 and EPA-HQ-OAR-2010-0505-7686.

flowback.[92] In November 2016, the EPA responded to a letter from API seeking clarification on this issue, stating, "any releases of gas or vapor during 'screenouts' and 'coil tubing cleanouts,' which occur during the initial flowback stage are not subject to control under section 60.5375a".[93] However, we have further assessed this topic and believe that the guidance we issued was incorrect. In the preamble to the final 2014 amendments, we stated regarding flowback: "…the first stage would begin with the first flowback from the well following hydraulic fracturing or refracturing, and would be characterized by high volumetric flow…" 79 FR 79024. In some situations, screenouts or coil tubing cleanouts may be necessary in order to remove proppant (sand) from the well so that high volumetric flow can occur, marking the beginning of the initial flowback stage. Therefore, screenouts and coil tubing cleanouts are not a part of flowback; rather, they are functional processes that allow for flowback to begin. It should be noted that this is consistent with the definition of hydraulic fracturing, which we stated requires high rate, extended flowback to expel fracture fluids and solids during completions. 40 CFR 60.5430a. For the reasons stated above, the November 2016 letter incorrectly states that screenouts and coil tubing cleanouts occur during the initial flowback stage. To clarify this point, we are proposing to revise the definition of flowback to expressly exclude these processes to avoid any future confusion. In addition, we are proposing definitions for these processes. A screenout is the first attempt to clear proppant from the wellbore. It involves flowing the well to a fracture tank in order to achieve maximum velocity and carry the proppant out of the well. If a screenout is unsuccessful in clearing the proppant from the wellbore, then a coil tubing cleanout is conducted. This involves running a string of coil tubing to the packed proppant and jetting the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface. It is after

[92] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.
[93] See Docket ID No. EPA-HQ-OAR-2010-0505-7722.

these processes that flowback begins and, subsequently, production. The EPA solicits comment on the proposed definitions for these processes.

Plug Drill-Outs. A plug drill-out is the removal of a plug (or plugs) that was used to conduct hydraulic fracturing in different sections of the well. Plug drill-outs are also functional processes that are necessary in order for flowback to begin. Therefore, the EPA is similarly proposing to exclude these processes from the definition of flowback.

Flowback Routed Through Permanent Separators. The EPA is proposing to streamline reporting and recordkeeping requirements for flowback routed through permanent separators to reduce burden on the regulated community. We consider a permanent separator to be one that handles flowback from a well or wells beginning when the flowback period begins and continuing to the startup of production. When routing flowback through permanent separators, some reporting and recordkeeping elements associated with well completions (*e.g.*, information about when a separator is hooked up or disconnected) become unnecessary because the separator is already connected to the well at the onset of flowback. In these situations, there is no initial flowback stage, and the separation flowback stage begins. Therefore, the EPA is proposing that operators do not need to record or report the date and time of each attempt to direct flowback to a separator for these situations. These streamlined recordkeeping and reporting requirements would not apply in situations where flowback is not routed through a permanent separator. The EPA is soliciting comments on these proposed revisions and additional ways to streamline reporting and recordkeeping.

2. Onshore Natural Gas Processing Plants

Capital Expenditure. We are proposing to correct the definition of "capital expenditure" promulgated at 40 CFR 60.5430a by replacing the reference to the year 2011 with the year 2015

in the formula in paragraph (2) of the definition. The definition of "capital expenditure" was among the issues related to 40 CFR part 60, subpart OOOO that the EPA reconsidered and addressed in the 2016 NSPS OOOOa. That definition is relevant to the equipment leaks standards for onshore natural gas processing plants that were originally promulgated in 1985 in 40 CFR part 60, subpart KKK, updated in 2012 in 40 CFR part 60, subpart OOOO, and carried over in 2016 in 40 CFR part 60, subpart OOOOa. As explained in the memorandum *Alternative Method for Determining Capital Expenditures (Thomas W. Rhoads to Docket A-80-44, July 21, 1983)*, located at Docket ID No. EPA-HQ-OAR-2017-0483. As explained in that memorandum, this method was developed to allow a facility to approximate the original costs of the facility using the replacement costs and the inflation index and therefore, providing an alternative method to the definition of "capital expenditure" in 40 CFR part 60, subpart A ("General Provisions").[94] The value for "Y" (the percent of replacement cost) is designed to take into account the age of the facility. Therefore, the replacement cost for a new facility should be the same as the original cost, or the value of "Y" should be closer to 1 for new facilities. Because the 2016 NSPS OOOOa applies to new sources constructed, reconstructed, or modified after September 18, 2015, the base year of 2015 is the correct year to reflect the age of the facility in this calculation.

However, for sources that commenced construction between January 1, 2015, and September 18, 2015, there is an issue using the value of "2015" because it results in a "zero" value for "X" for which there is no logarithmic solution. The EPA is, therefore, amending the definition so that the value of "Y" equals 1 if the affected process unit was constructed in 2015. The proposed amendment would address the mathematical issue for affected sources constructed

[94] See also *Equipment Leaks of VOC in Natural Gas Production Industry – Background for Promulgated Standards*, EPA-450/3-82-024b, May 1985, at 9-1.

in 2015 whiling leaving the calculation method intact for other affected sources. We are soliciting comment on the proposed amendment to the equation.

Notwithstanding this proposed amendment, as indicated above, the equation was developed as an alternative to the General Provisions definition of "capital expenditure." Since the General Provisions definition also applies, if calculation issues arise when applying the 2016 NSPS OOOOa equation, facilities should use the General Provisions to calculate capital expenditure. Facilities can also contact the EPA for guidance on how to apply the General Provisions definition for "capital expenditure" evaluations if necessary by utilizing 40 CFR 60.5 (Determination of construction or modification).

In addition, the EPA is soliciting comment and information to help inform us whether the current capital expenditure definition should be revised based on a ratio of consumer price indices (CPI), as requested by two petitioners.[95] Petitioners indicated that calculation of "capital expenditure" was designed to account for inflation. In supporting documentation provided from one petitioner[96] a plot of values prior to 1982 demonstrates a logarithmic function, which directly correlates to the CPI for the years 1950 through 1982. This was the information on which the "capital expenditure" equation was based. However, as described by the petitioners, the CPI takes a more linear function post-1982, while the "capital expenditure" equation remains with a logarithmic function. In practice, this could mean that the "P" value would be lower using the "capital expenditure" equation, thus resulting in modifications at lower expenditures than if the CPI were used. While we are proposing to update the existing equation with the corrected base year date of 2015, we are also soliciting comment on changing the calculation for the value of

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[95] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682 and EPA-HQ-OAR-2010-0505-7684.
[96] See *GPA Midstream New Source Performance Standards ("NSPS") Subpart OOOOa Petition for Review Technical Issues* located at Docket ID No. EPA-HQ-OAR-2010-0505-12361. March 1, 2017.

"Y" using the CPI. Specifically, we are soliciting comment on the petitioner's suggestion that the value for "Y" should be calculated using the CPI of the date of construction or reconstruction divided by the CPI of the date of component price data, or "CPI_N/CPI_{PD}".

VI. Implementation Improvements

Following publication of the 2016 NSPS OOOOa, we subsequently determined, following review of petitions and discussions with affected parties, that the final rule warrants correction and clarification in certain areas. Each of these areas is discussed below.

A. Reciprocating Compressors

The 2016 NSPS OOOOa includes an alternative to the work practice standards for reciprocating compressors. Operators may choose to gather rod packing emissions using a collection system that operates under negative pressure and then route emissions to a process via a CVS, as opposed to replacing the rod packing every 26,000 hours or 36 months. During the comment period for the proposal for the 2016 NSPS OOOOa, the EPA received feedback from various stakeholders, who noted that there were safety concerns with requiring the rod packing emissions to be collected under negative pressure. Specifically, commenters stated that operating the collection system under negative pressure may inadvertently introduce oxygen into the system.[97] In response to comments, the EPA stated that operation of the collection system under negative pressure was necessary in order to appropriately capture emissions.[98] However, the EPA did not respond to comments regarding safety concerns and is soliciting comment on the requirement that rod packing emissions be collected under negative pressure. The EPA is soliciting comment and supporting data on capture systems which are at least equivalent to the

[97] See Docket ID No. EPA-HQ-OAR-2010-0505-6884.
[98] See Docket ID No. EPA-HQ-OAR-2010-0505-7632, Chapter 7, page 7-37.

current systems and which could negate the necessity to capture emissions under negative pressure.

B. Storage Vessels

Pursuant to 40 CFR 60.5365a(e), owners and operators must calculate potential emissions from storage vessels in order to determine if control requirements apply. This calculation is based on the "maximum average daily throughput". During implementation of the 2016 NSPS OOOOa, several stakeholders requested clarification regarding this calculation. Specifically, the stakeholders have expressed confusion about what value constitutes the "maximum average daily throughput." This value was intended to represent the maximum daily production rate in the first 30-day period to each storage vessel. The EPA stated in its Response to Comments on the 2013 amendments to subpart OOOO, "we believe that the estimate of potential VOC emissions should be determined based on maximum emissions during the 30-day period rather than average emissions over that period".[99] We are proposing to remove the word "average" from this term to clarify the term applies to the maximum daily throughput. Additionally, we are clarifying how the "maximum daily throughput" must be calculated. Specifically, where a storage vessel is equipped with automation that measures and records liquid level in a data historian such that you can determine the throughput to the storage vessel for each day during the first 30 days of production, you must use the maximum value measured for any one of the 30 days. We understand that some storage vessels may not be equipped with automation and may not have daily measurements taken through other means. In such circumstances, we believe that the liquid height, and therefore volume, in the storage vessel would be measured at a minimum at the start and completion of loadout of liquids from the storage vessel. Frequency of loadout from each

[99] See Docket ID No. EPA-HQ-OAR-2010-0505-4639.

storage vessel (*i.e.*, "turnover rate") will vary depending on company or site-specific operations. Therefore, it is possible that a storage vessel could have multiple turnovers during the first 30-days of production. Where this occurs, you must determine the daily throughput for each of those periods and use the maximum of those throughput values to calculate the potential emissions from the storage vessel. We recognize that calculating daily throughput based on liquid level measurements at the beginning and end of a turnover period will necessarily average production throughput to the storage vessel over the number of days in the turnover period. However, recognizing that production declines, we are clarifying that this calculation, based on the first 30-days of production, represents the maximum potential emissions. We are soliciting comment on this clarification.

Further, inspection data and compliance reports for the 2016 NSPS OOOOa indicate that many operators determined that few or no storage vessels are affected facilities under the 2016 NSPS OOOOa. For example, review of the 2016 NSPS OOOOa compliance reports indicates that some operators may be incorrectly averaging emissions across storage tanks in tank batteries when determining the potential for VOC emissions. Both the 2012 NSPS OOOO and 2016 NSPS OOOOa specify that a storage vessel affected facility is "a single storage vessel" that "has the potential for VOC emissions equal to or greater than 6 tpy." 40 CFR 60.5365(e) and 60.5365a(e). In prior rulemakings, the EPA explained that storage vessel emission estimation methods for the potential for VOC emissions generally require information on both the composition and volumetric rate of the liquid entering the storage vessel, where the volumetric throughput is frequently calculated by recording the volume of liquid collected from the receiving vessel(s) over time. 79 FR 79026. Because the 2012 NSPS OOOO and 2016 NSPS OOOOa define the affected facility as "a single storage vessel," the determination of the potential for VOC

emissions must be based on the liquid throughput of each "single storage vessel," even where the storage vessel is part of a tank battery. Operators should ensure that the determination of the potential for VOC emissions reflects each storage vessel's actual configuration and operational characteristics. Furthermore, if a storage vessel's configuration or operational characteristics are intended to avoid the 2012 NSPS OOOO or 2016 NSPS OOOOa applicability, the NSPS General Provisions on circumvention at 40 CFR 60.12 may provide grounds for state or federal enforcement. Similarly, the EPA notes that affected facility determinations are allowed to account for legally and practically enforceable limits in determining the potential for VOC emissions for a storage vessel. However, 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. Given the potential for recurring emissions from controlled storage vessel thief hatches or other opening owing to operation and maintenance performance even where adequate design has been verified,[100] any limit on capture and control efficiency from storage vessels must include sufficient monitoring to timely identify and repair emissions from storage vessels to ensure the limit on capture and control efficiency is consistently achieved.

Where a storage vessel is part of a tank battery, some operators appear to derive the maximum daily throughput of a storage vessel in a battery by using the throughput to the entire battery (by using records of liquids collected from the battery over time) and dividing that figure by the number of storage vessels in the battery. This approach for determining a storage vessel's

[100] *Analysis of Consent Decree Reports from Noble Energy, Inc. as to Emissions Observations from Thief Hatches or Other Openings on Controlled Storage Vessels; Oil and Natural Gas Sector: Emission Standards for New, Reconstructed and Modified Sources Reconsideration – SAN 5719.8* located at Docket ID No. EPA-HQ-OAR-2017-0483.

maximum daily throughput is incorrect for certain operational configurations. For instance, where a tank battery is operated such that all pressurized liquids from the separator initially flow to only one storage vessel, and then overflow to the next, and so on (*i.e.,* in series or series flow), the first individual storage vessel's throughput would be the entire battery's throughput, not the entire battery's throughput apportioned evenly among the storage vessels. Dividing an entire battery's throughput by the number of storage vessels in the battery would greatly underestimate flash emissions from the first storage vessel connected in series, which is where liquid pressure drops from separator pressure to atmospheric pressure. However, such division could be appropriate where all liquids flow through a splitter system in a common header that ensures that all liquids initially flow in equal amounts to all storage vessels in a tank battery at all times since the liquid pressure drop would occur equally in each storage vessel in the battery. The EPA is soliciting comment and suggestions for how to clarify the calculation for application by stakeholders, including how to measure throughput, the appropriate timeframe for determining the throughput, and the appropriate averaging time for determining the throughput such that the maximum potential emissions from storage vessels may be determined.

C. Definition of Certifying Official

In response to petitions on NSPS OOOO, the EPA amended the definition of 'responsible official' in order to remove potential confusion in the regulated community and to clarify that the requirements of the NSPS were not associated with a permitting program.[101] Because the terms 'responsible official' and 'permitting authority' were similar to terms used in the Title V permitting program, the EPA changed the term 'responsible official' to 'certifying official' and replaced the term 'permitting authority' used in the definition with 'Administrator.'"[102] This

[101] 79 FR 79023-4.
[102] *Id.*

amended definition of 'certifying official' was carried forward into the 2015 NSPS OOOOa proposal. 80 FR 56694. The EPA received comments that the term 'certifying official' still includes references to permitting programs and is inconsistent with way the NSPS program operates.[103] In response to this comment, the EPA stated that the change made in the 2014 amendments "remove[d] any confusion".[104] Upon further evaluation of this issue, the EPA recognizes that continuing to include the language "facilities applying for or subject to a permit" in the definition of 'certifying official' is inappropriate for the NSPS program. Therefore, the EPA is proposing to amend this definition to remove the reference to permits. The EPA solicits comment on this proposed change.

D. Equipment in VOC Service less than 300 hours/year

In this action, the EPA is proposing to amend the requirements for equipment leaks at onshore natural gas processing plants. Specifically, we are proposing to include an exemption from monitoring for certain equipment that an owner or operator designates as being in VOC service less than 300 hr/yr.

When the 2007 requirements were promulgated, the EPA concluded that an exemption for certain equipment that is in VOC service less than 300 hr/yr was appropriate. In response to public comments on the 2006 NSPS VV/VVa proposal, we stated that such exemption was appropriate for equipment that is used only during emergencies, used as a backup, or that is in service only during startup and shutdown.[105] In these situations, the operating schedule of the equipment is unpredictable and likely at widely spaced and varying intervals. Planning for monitoring is more challenging and the effort outweighs the limited potential gain in emissions.

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[103] See Docket ID No. EPA-HQ-OAR-2010-0505-6881.
[104] See Docket ID No. EPA-HQ-OAR-2010-0505-7632, Chapter 15, page 15-284.
[105] See Docket ID No. EPA-HQ-OAR-2006-0699-0094.

The EPA is proposing to include this same exemption for equipment at onshore natural gas processing plants used only during emergencies, used as a backup, or that is in service only during startup and shutdown.

E. Reporting and Recordkeeping

The EPA is proposing to streamline certain reporting and recordkeeping requirements to reduce burden on the regulated industry. The proposed changes can be seen in section 60.5420a. Additionally, the proposed reporting elements can be seen in the draft electronic reporting template, located at Docket ID No. EPA-HQ-OAR-2017-0483. We solicit comment on these proposed revisions and additional ways to streamline reporting and recordkeeping.

We are also proposing revisions to accommodate the submittal of CBI data in annual reports, as well as additional clarifications for reporting requirements during outages of the Compliance and Emissions Data Reporting Interface (CEDRI) or EPA's Central Data Exchange (CDX) systems, or during a force majeure event. These proposed changes can be seen in section 60.5420a.

F. Technical Corrections and Clarifications

We are proposing to revise the 2016 NSPS OOOOa to include the following technical corrections and clarifications.

- Revise paragraphs 60.5385a(a)(1), 60.5410a(c)(1), 60.5415a(c)(1), 60.5420a(b)(4)(i) and 60.5420a(c)(3)(i) to clarify that hours or months of operation at reciprocating compressor facilities should be measured beginning with the later of initial startup, the effective date of the requirement (August 2, 2016), or the last rod packing replacement.
- Revise paragraph 60.5393a(b)(3)(ii) to correctly cross-reference to paragraph (b)(3)(i) of that section.

- Revise paragraph 60.5397a(c)(8) to clarify the calibration requirements when Method 21 of Appendix A-7 to Part 60 is used for fugitive emission monitoring.
- Revise paragraph 60.5397a(d)(3) to correctly cross-reference paragraphs (g)(3) and (g)(4) of that section.
- Revise paragraph 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 Alaskan North Slope are not subject to any monitoring requirements.
- Revise paragraph 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. This proposed revision reflects that the 2016 NSPS OOOOa did not finalize requirements for pneumatic pumps in the gathering and boosting and transmission and storage segments. 81 FR 35850.
- Revise paragraph 60.5411a(a)(1) to remove the reference to paragraphs 60.5412a(a) and (c) for reciprocating compressor affected facilities.
- Revise paragraph 60.5411a(d)(1) to remove the reference to storage vessels, as this paragraph applies to all the sources lists in paragraph 60.5411a(d), not only storage vessels.
- Revise paragraphs 60.5412a(a)(1), 60.5412a(a)(1)(iv), 60.5412a(d)(1)(iv) and 60.5412a(d)(1)(iv)(D) to clarify that all boilers and process heaters must introduce the vent stream into the flame zone and that the performance requirement option for combustion control devices on centrifugal compressors and storage vessels is to introduce the vent stream with the primary fuel or as the primary fuel. This is the consistent with

the performance testing exemption in section 60.5413a and continuous monitoring exemption in section 60.5417a for boilers and process heaters that introduce the vent stream with the primary fuel or as the primary fuel.

- Revise paragraph 60.5412a(c) to correctly reference both paragraphs (c)(1) and (c)(2) of that section, for managing carbon in a carbon adsorption system.
- Revise paragraph 60.5413a(d)(5)(i) to reference fused silica-coated stainless steel evacuated canisters instead a specific name brand product.
- Revise paragraph 60.5413a(d)(9)(iii) to reference the total hydrocarbon span for the alternative range is on an as propane basis, just as the recommended total hydrocarbon span is on an as propane basis.
- Revise paragraph 60.5413a(d)(12) to clarify that all data elements must be submitted for each test run.
- Revise paragraph 60.5415a(b)(3) to reference all the applicable reporting and recordkeeping requirements.
- Revise paragraph 60.5416a(a)(4) to correctly cross-reference paragraph 60.5411a(a)(3)(ii).
- Revise paragraph 60.5417a(a) to clarify requirements for controls not specifically listed in paragraph (d) of that section.
- Revise paragraph 60.5422a(b) to correctly cross-reference paragraphs 60.487a(b)(1) through (3) and (b)(5).
- Revise paragraph 60.5422a(c) to correctly cross-reference paragraph 60.487a(c)(2)(i) through (iv) and (c)(2)(vii) through (viii).

- Revise paragraph 60.5423a(b) to simplify the reporting language and clarify what data is required in the report of excess emissions for sweetening unit affected facilities.
- Revise paragraph 60.5430a to remove the phrase "including but not limited to" from the "fugitive emissions component" definition. This proposed revision reflects that in the response to comments document for the 2016 NSPS OOOOa we stated we were removing this phrase.[106]
- Revise paragraph 60.5430a to remove the phrase "at the sales meter" from the "low pressure well" definition. 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 section 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 paragraphs 60.5393a(f), 60.5410a(e)(8), 60.5411a(e), 60.5415a(b), 60.5415a(b)(4), 60.5416a(d), 60.5420a(b), 60.5420a(b)(13) and introductory text in 60.5411a, 60.5416a to remove the language added in the "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Grant of Reconsideration and Partial Stay" (June 5, 2017), which was vacated by the U.S. Court of Appeals for the D.C. Circuit on July 3, 2017.

VII. Impacts of This Proposed Rule

A. What are the air impacts?

[106] See Docket ID No. EPA-HQ-OAR-2010-0505-7632, Chapter 4, page 4-319.

For this action, the EPA estimated the change in emissions that will occur due to the implementation of the proposed NSPS reconsideration for the analysis years of 2019 through 2025. We estimate impacts beginning in 2019 to reflect the year implementation of this reconsideration will begin. We estimate impacts through 2025 to illustrate the continued compound effect of this rule over a longer period. We do not estimate impacts after 2025 for reasons including limited information, as explained in the RIA (Regulatory Impact Analysis). The regulatory impact estimates for 2025 include sources newly affected in 2025 as well as the accumulation of affected sources from 2016 to 2024 that are also assumed to be in continued operation in 2025, thus incurring compliance costs and emissions reductions in 2025.

We have estimated that, over the 2019 through 2025 timeframe, the proposed NSPS reconsideration would increase methane emissions by about 200,000 short tons, and VOC emissions by about 56,000 tons from facilities affected by this reconsideration compared to emissions under the 2018 updated baseline, as described in the RIA. The proposed reconsideration is also expected to concurrently increase about 2,100 tons hazardous air pollutants (HAP) from 2019 through 2025.

As described in the TSD and RIA for this rule, the EPA projected affected facilities using a combination of historical data from the United States GHG Inventory, projected activity levels taken from the Energy Information Administration (EIA's) Annual Energy Outlook (AEO), and oil and natural gas production information from DrillingInfo, a private company that provides information and analysis to the energy sector. The EPA also considered state regulations with similar requirements to the proposed NSPS in projecting affected sources for impacts analyses supporting this rule.

B. What are the energy impacts?

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

C. What are the compliance cost savings?

The EPA estimates the present value (PV) of compliance cost savings of the proposed reconsideration over 2019-2025, discounted back to 2016, will be $234 million (in 2016 dollars) under a 7 percent discount rate, and $299 million under a 3 percent discount rate, not including the forgone producer revenues associated with the decrease in the recovery of saleable natural gas. The equivalent annualized value (EAV) of these cost savings are $41 million per year using a 7 percent discount rate and $47 million per year using a 3 percent discount rate. In this analysis, we use the 2018 AEO projection of natural gas prices to estimate the value of the change in the recovered gas at the wellhead. After accounting for the change in these revenues, the estimate of the PV of compliance cost savings of the proposed reconsideration over 2019-2025, discounted back to 2016, are estimated to be $209 million under a 7 percent discount rate, and $265 million under a 3 percent discount rate; the corresponding estimates of the EAV of cost savings after accounting for the forgone revenues are $36 million per year under a 7 percent discount rate, and $41 million per year under 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 OOOOa on the United States energy system. The NEMS is a publicly-available model of the United States energy economy developed and maintained by the EIA and is used to produce the AEO, a reference publication that provides detailed forecasts of the United States energy economy.

The EPA estimated small impacts of that rule over the 2020 to 2025 period relative to the baseline for that rule. The proposed reconsideration is estimated to result in a decrease in total costs compared to the updated 2018 baseline, and the 2016 NSPS OOOOa, with the change in costs affecting a subset of the total costs estimated for the 2016 NSPS OOOOa. Therefore, the EPA expects that this deregulatory action, if finalized, would partially ameliorate the impacts estimated for the final NSPS in the 2016 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 particular concern in the current economic climate given continued interest in the employment impact of regulations such as this proposed rule.

The EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, control activities, and labor associated with new reporting and recordkeeping requirements in the 2016 NSPS OOOOa RIA. For the proposed reconsideration, EPA expects there will be slight reductions in the labor required for compliance-related activities

associated with the 2016 NSPS OOOOa requirements relating to fugitive emissions and inspections of closed vent systems. However, due to uncertainties associated with how the proposed reconsideration will influence the portfolio of activities associated with fugitive emissions-related requirements, EPA is unable to provide quantitative estimates of compliance-related labor changes.

E. What are the forgone benefits of the proposed standards?

The EPA estimated the forgone domestic climate benefits from the methane emissions associated with this reconsideration using an interim measure of the domestic social cost of methane (SC-CH_4). The SC-CH_4 estimates used here were developed under E.O. 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. E.O. 13783 directed agencies to ensure that estimates of the social cost of greenhouse gases used in regulatory analyses "are based on the best available science and economics" and are consistent with the guidance contained in OMB Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (E.O. 13783, Section 5(c)). In addition, E.O. 13783 withdrew the technical support documents (TSDs) and the August 2016 Addendum to these TSDs describing the global social cost of greenhouse gas 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 (IWG) that included the EPA and other executive branch entities and were used in the 2016 NSPS RIA.

The forgone benefits of the proposed reconsideration are estimated in comparison to an updated baseline with the 2016 NSPS OOOOa and the March 12, 2018 amendments with respect

to the Alaskan North Slope in place. The EPA estimates the PV of the forgone domestic climate benefits over 2019-2025, discounted back to 2016, will be $7.2 million under a 7 percent discount rate and $28 million under a 3 percent discount rate. The EAV of these forgone benefits is $1.2 million per year under a 7 percent discount rate and $4.4 million per year under a 3 percent discount rate. These values represent only a partial accounting of domestic climate impacts from methane emissions, and also do not account for health effects of ozone exposure from the increase in methane emissions.

The EPA expects that the forgone VOC emission reductions may degrade air quality and adversely affect health and welfare effects associated with exposure to ozone, $PM_{2.5}$, and HAP, however data limitations prevent us from quantifying forgone VOC-related health benefits. This omission should not imply that these forgone benefits may not exist; rather, it reflects the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. As described in the RIA, with these data currently unavailable, we are unable to estimate forgone health benefits estimates for this rule due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with HAP and VOC reductions.

VIII. Statutory and Executive Order Reviews

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

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

This action is a significant regulatory action that was submitted to the OMB for review because it raises novel legal or policy issues. Any changes made in response to OMB recommendations have been documented in the docket.

In addition, the EPA prepared a Regulatory Impact Analysis (RIA) of the potential costs and benefits associated with this action. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 2 shows the present value and equivalent annualized value results of the cost and benefits analysis for the proposed rule for 2019 through 2025, discounted back to 2016 using a discount rate of 7 percent. The table also shows the total increase in emissions from 2019 through 2025 from this proposed reconsideration. When discussing net benefits, we modify the relevant terminology to be more consistent with traditional net benefits analysis. In the following table, we refer to the cost savings as presented in section 2 of the RIA, and in section VII.C, above, as the "benefits" of this proposed action and the forgone benefits as presented in section 3 of the RIA, and in section VII.E, above, as the "costs" of this proposed action. The net benefits are the benefits (cost savings) minus the costs (forgone benefits).

Table 2. Summary of the Present Value and Equivalent Annualized Value of the Monetized Forgone Benefits, Cost Savings and Net Benefits of the Proposed Oil And Natural Gas Reconsideration from 2019 through 2025 (Millions of 2016$)

	Present Value	**Equivalent Annualized Value**
Benefits (Total Cost Savings)	$209 million	$36 million
Costs (Forgone Domestic Climate Benefits)	$7.2 million	$1.2 million
Net Benefits	$201 million	$35 million
	Non-monetized climate impacts from increases in methane emissions	

Non-monetized Forgone Benefits	Health effects of $PM_{2.5}$ and ozone exposure from an increase of 56,000 tons of VOC from 2019 through 2025
	Health effects of HAP exposure from an increase of 2,100 tons of HAP from 2019 through 2025
	Health effects of ozone exposure from an increase of 200,000 short tons of methane from 2019 through 2025
	Visibility impairment
	Vegetation effects

Estimates may not sum due to independent rounding

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

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

C. Paperwork Reduction Act (PRA)

A summary of the information collection activities submitted to the Office of Management and Budget (OMB) for the final action titled, Standards of Performance for Crude Oil and Natural Gas Facilities for Construction, Modification, or Reconstruction (2016 NSPS OOOOa) under the PRA, and assigned EPA ICR Number 2523.01, can be found at 81 FR 35890. You can find a copy of the ICR in the 2016 NSPS OOOOa docket (EPA-HQ-OAR-2010-0505-7626). This proposed reconsideration revises the information collection activities of 2016 NSPS OOOOa. The revised information collection activities in this proposed rule have been submitted for approval to OMB under the PRA. The revised ICR document that the EPA prepared has been assigned EPA ICR number 2523.02. You can find a copy of the revised ICR in the docket for this rule.

The proposed changes to the 2016 NSPS OOOOa information collection activities would reduce the burden on the regulated industry associated with reporting and recordkeeping requirements. Proposed amendments to the reporting and recordkeeping requirements are

presented in section 60.5420a. Other information collection activity reductions would result from proposed amendments that streamline and align monitoring requirements (and associated recordkeeping) in the rule.

The estimated average annual burden (averaged over the first 3 years after the effective date of the standards) for the recordkeeping and reporting requirements associated with the proposed amendments to subpart OOOOa for the estimated 2,893 owners and operators subject to the rule is 156,188 labor hours, with an average annual cost of $9,615,691 (2016$) over the three-year period. The information collection activities associated with the proposed amendments would result in an estimated average annual burden reduction of 8 percent compared to the previously-submitted 2016 NSPS OOOOa ICR (2016$).

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.

Submit your comments on the Agency's need for this information, the accuracy of the provided revised burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to RIA_submissions@omb.eop.gov, Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than **[INSERT DATE 30 DAYS AFTER PUBLICATION IN THE FEDERAL REGISTER]**. The EPA will respond to any ICR-related comments in the 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 proposed rule, including small entities, is reduced compared to the 2016 NSPS 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 of 1995 (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. 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 it is not economically significant as defined in Executive Order 12866. The 2016 NSPS OOOOa, as discussed in the RIA,[107] was anticipated to reduce emissions of methane, VOC, and HAPs, and some of the benefits of reducing these pollutants would have accrued to children. However, new data and analysis have affected expectations about how extensive the impact of the fugitive emissions program in the 2016 NSPS OOOOa would have on these benefits. Furthermore, while the proposed amendment is expected to decrease the impact of the fugitive emissions program in the 2016 NSPS OOOOa on these benefits, as discussed in Chapter 1 of the RIA, the potential decrease in emission reduction (and thus the benefit) from the proposed amendment is minimal compared to the overall emission reduction that would continue to be achieved under the amended 40 CFR part 60, subpart OOOOa.

Moreover, the proposed 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 proposed 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. For the reasons stated above, we do not believe this small decrease in emission reduction from this action will have a disproportionate adverse effect on children's health.

[107] See Chapter 4, "Economic Impact Analysis and Distributional Assessments", of the RIA.

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. The basis for this determination can be found in the 2016 NSPS OOOOa (81 FR 35894).

J. National Technology Transfer and Advancement Act (NTTAA)

This action involves technical standards.[108] 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 were identified for EPA Methods 1A, 2A, 2D, 21, and 22 and none were brought to its attention in comments. All potential standards were reviewed to determine the practicality of the voluntary consensus standards (VCS) for this rule.

Two VCS were identified as an acceptable alternative to EPA test methods for the purpose of this rule. First, ANSI/ASME PTC 19-10–1981, Flue and Exhaust Gas Analyses (Part 10) was identified to be used in lieu of EPA Methods 3B, 6, 6A, 6B, 15A and 16A manual portions only and not the instrumental portion. This standard includes manual and instructional methods of analysis for carbon dioxide, carbon monoxide, hydrogen sulfide, nitrogen oxides, oxygen, and sulfur dioxide. Second, ASTM D6420-99 (2010), "Test Method for Determination

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

of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry" is an acceptable alternative to EPA Method 18 with the following caveats, only use when the target compounds are all known and the target compounds are all listed in ASTM D6420 as measurable. ASTM D6420 should never be specified as a total VOC Method. (ASTM D6420-99 (2010) is not incorporated by reference in 40 CFR part 60.) The search identified 19 VCS that were potentially applicable for this rule in lieu of EPA reference methods. However, these have been determined to not be practical due to lack of equivalency, documentation, validation of data and other important technical and policy considerations. For additional information, please see the 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 proposed action is unlikely to 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). The 2016 NSPS OOOOa was anticipated to reduce emissions of methane, VOC, and HAPs, and some of the benefits of reducing these pollutants would have accrued to minority populations, low-income populations and/or indigenous peoples. However, new data and analysis have affected expectations about how extensive the impact of the fugitive emissions program in the 2016 NSPS OOOOa would have on these benefits. Furthermore, while these communities may experience forgone benefits as a result of this action, as discussed in Chapter 1 of the RIA, the potential foregone emission reductions (and related benefits) from the proposed

amendments is minimal compared to the overall emission reductions (and related benefits) from the 2016 NSPS.

Moreover, the proposed 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 proposed 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

For the reasons stated above, the EPA believes that this proposed action is unlikely to have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples. We note that the potential impacts of this proposed action are not expected to be experienced uniformly, and the distribution of avoided compliance costs associated with this action depends on the degree to which costs would have been passed through to consumers.

List of Subjects in 40 CFR Part 60

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

Dated: _____.

E. Scott Pruitt,

Administrator.

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

PART 60-- STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015

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§60.5360a What is the purpose of this subpart?

§60.5365a Am I subject to this subpart?

§60.5370a When must I comply with this subpart?

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

§60.5380a What GHG and VOC standards apply to centrifugal compressor affected facilities?

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

§60.5390a What GHG and VOC standards apply to pneumatic controller affected facilities?

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

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

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

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

§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?

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

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

§60.5402a What are the alternative means of emission limitations for GHG and VOC equipment leaks from onshore natural gas processing plants?

§60.5405a What standards apply to sweetening unit affected facilities at onshore natural gas processing plants?

§60.5406a What test methods and procedures must I use for my sweetening unit affected facilities at onshore natural gas processing plants?

§60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

§60.5408a What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

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

§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?

§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?

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

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

§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?

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

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

§60.5421a What are my additional recordkeeping requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

§60.5422a What are my additional reporting requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

§60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

§60.5425a What parts of the General Provisions apply to me?

§60.5430a What definitions apply to this subpart?

§60.5432a How do I determine whether a well is a low pressure well using the low pressure well equation?

§§60.5433a-60.5499a [Reserved]

Table 1 to Subpart OOOOa of Part 60—Required Minimum Initial SO_2 Emission Reduction Efficiency (Z_i)

Table 2 to Subpart OOOOa of Part 60—Required Minimum SO_2 Emission Reduction Efficiency (Z_c)

Table 3 to Subpart OOOOa of Part 60—Applicability of General Provisions to Subpart OOOOa

§60.5360a What is the purpose of this subpart?

(a) This subpart establishes emission standards and compliance schedules for the control of the pollutant greenhouse gases (GHG). The greenhouse gas standard in this subpart is in the form of a limitation on emissions of methane from affected facilities in the crude oil and natural gas source category that commence construction, modification, or reconstruction after September 18, 2015. This subpart also establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities in the crude oil and natural gas source category that commence construction, modification or reconstruction after September 18, 2015. The effective date of the rule is August 2, 2016.

(b) *Prevention of Significant Deterioration (PSD) and title V thresholds for Greenhouse Gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from

affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, §51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Clean Air Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 71.2.

§60.5365a Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section for which you commence construction, modification, or reconstruction after September 18, 2015.

(a) Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing. The provisions of this paragraph do not

affect the affected facility status of well sites for the purposes of §60.5397a. The provisions of paragraphs (a)(1) through (4) of this section apply to wells that are hydraulically refractured:

(1) A well that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of §60.5375a(a)(1) through (4) are met. However, hydraulic refracturing of a well constitutes a modification of the well site for purposes of paragraph (i)(3)(iii) of this section, regardless of affected facility status of the well itself.

(2) A well completion operation following hydraulic refracturing not conducted pursuant to §60.5375a(a)(1) through (4) is a modification to the well.

(3) Except as provided in §60.5365a(i)(3)(iii), refracturing of a well, by itself, does not affect the modification status of other equipment, process units, storage vessels, compressors, pneumatic pumps, or pneumatic controllers.

(4) A well initially constructed after September 18, 2015, that conducts a well completion operation following hydraulic refracturing is considered an affected facility regardless of this provision.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(d) Each pneumatic controller affected facility:

(1) Each pneumatic controller affected facility not located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

(2) Each pneumatic controller affected facility located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller.

(e) Each storage vessel affected facility, which is a single storage vessel with the potential for VOC emissions equal to or greater than 6 tpy as determined according to this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this subsection. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority.

(1) For each new, modified or reconstructed storage vessel you must determine the potential for VOC emissions within 30 days after liquids first enter the storage vessel, except as provided in paragraph (e)(3)(iv) of this section. For each new, modified or reconstructed storage vessel receiving liquids pursuant to the standards for well affected facilities in §60.5375a, including wells subject to §60.5375a(f), you must determine the potential for VOC emissions within 30 days after startup of production of the well.

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

(3) For storage vessels not subject to a legally and practically enforceable limit in an operating permit or other requirement established under federal, state, local or tribal authority,

any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(3)(i) through (iv) of this section.

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

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

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

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

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

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

(f) The group of all equipment within a process unit is an affected facility. (1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by §§60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of §§60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG, or GGGa of this part.

(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in §60.5423a(c) but are not required to comply with §§60.5405a through 60.5407a and §§60.5410a(g) and 60.5415a(g).

(4) Sweetening facilities producing acid gas that is completely re-injected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§60.5405a through 60.5407a, 60.5410a(g), 60.5415a(g), and 60.5423a.

(h) Each pneumatic pump affected facility:

(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump.

(2) For well sites, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump. A single natural gas-driven diaphragm pump that is in operation less than 90 days per calendar year is not an affected facility under this subpart provided the owner/operator keeps records of the days of operation each calendar year and submits such records to the EPA Administrator (or delegated enforcement authority) upon request. For the purposes of this section, any period of operation during a calendar day counts toward the 90 calendar day threshold.

(i) Except as provided in §60.5365a(i)(2), the collection of fugitive emissions components at a well site, as defined in §60.5430a, is an affected facility.

(1) [Reserved]

(2) A well site that only contains one or more wellheads is not an affected facility under this subpart. The affected facility status of a separate tank battery surface site has no effect on the affected facility status of a well site that only contains one or more wellheads.

(3) For purposes of §60.5397a, a "modification" to a well site occurs when:

(i) A new well is drilled at an existing well site;

(ii) A well at an existing well site is hydraulically fractured; or

(iii) A well at an existing well site is hydraulically refractured.

(4) For purposes of §60.5397a, a "modification" to a separate tank battery occurs when:

(i) Any of the actions in paragraphs §60.5365a(i)(3)(i) through (iii) occurs at an existing separate tank battery;

(ii) A well sending production to an existing separate tank battery is modified, as defined in §60.5365a(i)(3)(i) through (iii); 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 separate tank battery.

(j) The collection of fugitive emissions components at a compressor station, as defined in §60.5430a, is an affected facility. For purposes of §60.5397a, a "modification" to a compressor station occurs when:

(1) An additional compressor is installed at a compressor station; or

(2) One or more compressors at a compressor station is replaced by one or more compressors of greater total horsepower than the compressor(s) being replaced. When one or more compressors is replaced by one or more compressors of an equal or smaller total horsepower than the compressor(s) being replaced, installation of the replacement compressor(s) does not trigger a modification of the compressor station for purposes of §60.5397a.

§60.5370a When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than August 2, 2016 or upon startup, whichever is later.

(b) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. The provisions for exemption from compliance during

periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

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

If you are the owner or operator of a well affected facility as described in §60.5365a(a) that also meets the criteria for a well affected facility in §60.5365(a) of subpart OOOO of this part, you must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with paragraphs (a) through (g) of this section. If you own or operate a well affected facility as described in §60.5365a(a) that does not meet the criteria for a well affected facility in §60.5365(a) of subpart OOOO of this part, you must reduce GHG and VOC emissions by complying with paragraphs (f)(3), (f)(4) or (g) for each well completion operation with hydraulic fracturing prior to November 30, 2016, and you must comply with paragraphs (a) through (g) of this section for each well completion operation with hydraulic fracturing on or after November 30, 2016.

(a) Except as provided in paragraph (f) and (g) of this section, for each well completion operation with hydraulic fracturing you must comply with the requirements in paragraphs (a)(1) through (4) of this section. You must maintain a log as specified in paragraph (b) of this section.

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

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

(ii) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the recovered liquids into the well or another well, or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an onsite fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is technically infeasible to route the recovered gas as required above, follow the requirements in paragraph (a)(3) of this section. If, at any time during the separation flowback stage, it is technically infeasible for a separator to function, you must comply with paragraph (a)(1)(i) of this section.

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

(A) A well that is not hydraulically fractured or refractured with liquids, or that does not generate condensate, intermediate hydrocarbon liquids, or produced water such that there is no liquid collection system at the well site is not required to have a separator onsite.

(B) If conditions allow for liquid collection, then the operator must immediately stop the well completion operation, install a separator, and restart the well completion operation in accordance with §60.5375a(a)(1).

(C) The owner or operator of a well that meets the criteria of paragraph (a)(1)(iii)(A) or (B) of this section must submit the report in §60.5420a(b)(2) and maintain the records in §60.5420a(c)(1)(iii).

(2) [Reserved]

(3) If it is technically infeasible to route the recovered gas as required in §60.5375a(a)(1)(ii), then you must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(4) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

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

(c) You must demonstrate initial compliance with the standards that apply to well affected facilities as required by §60.5410a(a).

(d) You must demonstrate continuous compliance with the standards that apply to well affected facilities as required by §60.5415a(a).

(e) You must perform the required notification, recordkeeping and reporting as required by §60.5420a(a)(2), (b)(1) and (2), and (c)(1).

(f) For each well affected facility specified in paragraphs (f)(1) and (2) of this section, you must comply with the requirements of paragraphs (f)(3) and (4) of this section.

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

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

(3) You must comply with either paragraph (f)(3)(i) or (f)(3)(ii) of this section, unless you meet the requirements in paragraph (g) of this section. You must also comply with paragraph (b) of this section.

(i) Route all flowback to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

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

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

(g) For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, you must comply with paragraphs (g)(1) and (2) of this section.

(1) You must maintain records specified in §60.5420a(c)(1)(vi).

(2) You must submit reports specified in §60.5420a(b)(1) and (2).

§60.5380a What GHG and VOC standards apply to centrifugal compressor affected facilities?

You must comply with the GHG and VOC standards in paragraphs (a) through (d) of this section for each centrifugal compressor affected facility.

(a)(1) You must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411a(b). The cover must be connected through a closed vent system that meets the requirements of §60.5411a(a) and (d) and the closed vent system must be routed to a control device that meets the conditions specified in §60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

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

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

(d) You must perform the reporting as required by §60.5420a(b)(1) and (3), and the recordkeeping as required by §60.5420a(c)(2), (6) through (11), and (17), as applicable.

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

You must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

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

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

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

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

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

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

(d) You must perform the reporting as required by §60.5420a(b)(1) and (4) and the recordkeeping as required by §60.5420a(c)(3), (6) through (9), and (17), as applicable.

§60.5390a What GHG and VOC standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the GHG and VOC standards, based on natural gas as a surrogate for GHG and VOC, in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from this requirement.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety and positive actuation. However, you must tag such pneumatic controller with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in §60.5420a(c)(4)(ii).

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification

information that allows traceability to the records for that pneumatic controller as required in §60.5420a(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in §60.5420a(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by §60.5410a(d).

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by §60.5415a(d).

(f) You must perform the reporting as required by §60.5420a(b)(1) and (5) and the recordkeeping as required by §60.5420a(c)(4).

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

For each pneumatic pump affected facility you must comply with the GHG and VOC standards, based on natural gas as a surrogate for GHG and VOC, in either paragraph (a) or (b) of this section, as applicable, on or after November 30, 2016.

(a) Each pneumatic pump affected facility at a natural gas processing plant must have a natural gas emission rate of zero.

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

(1) [Reserved]

(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.

(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)(2) of this section within 30 days of startup of the control device or within 30 days of the ability to route to a process.

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

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

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

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

(iii) The assessment of technical feasibility to route emissions from the pneumatic pump to an existing control device onsite or to a process shall include, but is not limited to, safety considerations, distance from the control device, pressure losses and differentials in the closed vent system and the ability of the control device to handle the pneumatic pump emissions which are routed to them. The assessment of technical infeasibility shall be prepared under the direction or supervision of the in-house engineer or qualified professional engineer who signs the certification in accordance with paragraph (b)(2)(ii) of this section.

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

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

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

(d) You must demonstrate initial compliance with standards that apply to pneumatic pump affected facilities as required by §60.5410a(e).

(e) You must perform the reporting as required by §60.5420a(b)(1) and (8) and the recordkeeping as required by §60.5420a(c)(6) through (10), (16), and (17), as applicable.

(f) [Reserved]

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

EFFECTIVE DATE NOTE: At 82 FR 25733, June 5, 2017, in §60.5393a, paragraphs (b) and (c) were stayed until Aug. 31, 2017.

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

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

(a) You must comply with the requirements of paragraphs (a)(1) and (2) of this section. After 12 consecutive months of compliance with paragraph (a)(2) of this section, you may continue to comply with paragraph (a)(2) of this section, or you may comply with paragraph (a)(3) of this section, if applicable. If you choose to meet the requirements in paragraph (a)(3) of

this section, you are not required to comply with the requirements of paragraph (a)(2) of this section except as provided in paragraphs (a)(3)(i) and (ii) of this section.

(1) Determine the potential for VOC emissions in accordance with §60.5365a(e).

(2) Reduce VOC emissions by 95.0 percent within 60 days after startup. For storage vessel affected facilities receiving liquids pursuant to the standards for well affected facilities in §60.5375a(a)(1)(i) or (ii), you must achieve the required emissions reductions within 60 days after startup of production as defined in §60.5430a.

(3) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology, and the calculations must be based on the average throughput for the month. You may no longer comply with this paragraph and must instead comply with paragraph (a)(2) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (a)(3)(i) or (ii) of this section.

(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (a)(2) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.

(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected

facility, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination.

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

(2) If you use a floating roof to reduce emissions, you must meet the requirements of §60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

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

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

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

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

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

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

(d) Compliance, notification, recordkeeping, and reporting. You must comply with paragraphs (d)(1) through (3) of this section.

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

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

(3) You must perform the required reporting as required by §60.5420a(b)(1) and (6) and the recordkeeping as required by §60.5420a(c)(5) through (8), (12) through (14), and (17), as applicable.

(e) Exemptions. This subpart does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, and 40 CFR part 63, subparts G, CC, HH, or WW.

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

For each affected facility under §60.5365a(i) and (j), you must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with the requirements of paragraphs (a) through (j) of this section. These requirements are independent of the closed vent system and cover requirements in §60.5411a.

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

(b) You must develop an emissions monitoring plan that covers the collection of fugitive emissions components at well sites and compressor stations within each company-defined area in accordance with paragraphs (c) and (d) of this section.

(c) Fugitive emissions monitoring plans must include the elements specified in paragraphs (c)(1) through (8) of this section, at a minimum.

(1) Frequency for conducting surveys. Surveys must be conducted at least as frequently as required by paragraphs (f) and (g) of this section.

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

(3) Manufacturer and model number of fugitive emissions detection equipment to be used.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (h) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using optical gas imaging, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

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

(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of $\leq$60g/hr from a quarter inch diameter orifice.

(ii) Procedure for a daily verification check.

(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(v) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (e.g., steam).

(vi) Training and experience needed prior to performing surveys.

(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

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

(i) Verification that your monitoring equipment meets the requirements specified in Section 6.0 of Method 21 at 40 CFR part 60, appendix A-7. For purposes of instrument capability, the fugitive emissions definition shall be 500 ppm or greater methane using a FID-based instrument. If you wish to use an analyzer other than a FID-based instrument, you must develop a site-specific fugitive emission definition that would be equivalent to 500 ppm methane using a FID-based instrument (e.g., 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to your compound of interest).

(ii) Procedures for conducting surveys. At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of Method 21 at 40 CFR part 60, appendix A-7, including Section 8.3.1.

(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 calibration 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 these readings by the initial calibration values 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 OGI, your plan must include a sitemap or plot plan and the information in paragraph (d)(1)(i) or (ii) through (iv):

(i) A defined observation path that ensures that all fugitive emissions components are within sight of the path. The observation path must account for interferences.

(ii) For closed vent systems regulated under this section, a narrative description of how the closed vent system will be monitored, including a description and the location of all fugitive emissions components located on the closed vent system. The sitemap or plot plan must include the location of each closed vent system.

(iii) For controlled storage vessels regulated under this section, a narrative description of how the storage vessel will be monitored including a description and location of all fugitive emissions components located on the controlled storage vessel. The sitemap or plot plan must include the location of each controlled storage vessel.

(iv) For all other fugitive emissions components not associated with a closed vent system or controlled storage vessel regulated under this section, a narrative description of how the fugitive emissions components will be monitored, including a description and location of all fugitive emissions components. The description and location of fugitive emissions components may be grouped by unit operations (*e.g.*, separator, heater/treater, glycol dehydrator). The sitemap or plot plan must include the location of each unit operation.

(2) If you are using Method 21, your plan must include a list of fugitive emissions components to be monitored and method for determining location of fugitive emissions components to be monitored in the field (*e.g.* tagging, identification on a process and instrumentation diagram, etc.). If you are using OGI, you may comply with this requirement in lieu of paragraph (d)(1) of this section.

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

(e) Each monitoring survey shall observe each fugitive emissions component, as defined in §60.5430a, for fugitive emissions.

(f)(1) You must conduct an initial monitoring survey within 60 days of the startup of production, as defined in §60.5430a, for each collection of fugitive emissions components at a new well site or by June 3, 2017, whichever is later. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 60 days of the first day of production for each collection of fugitive emission components after the modification or by June 3, 2017, whichever is later. 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 later.

(2) You must conduct an initial monitoring survey within 60 days of the startup of a new compressor station for each new collection of fugitive emissions components at the new compressor station or by June 3, 2017, whichever is later. For a modified collection of fugitive components at a compressor station, the initial monitoring survey must be conducted within 60 days of the modification or by June 3, 2017, whichever is later. 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 later.

(g) A monitoring survey of each collection of fugitive emissions components at a well site or at a compressor station must be performed at the frequencies specified in paragraphs (g)(1) and (2) of this section, with the exceptions noted in paragraphs (g)(3), (4), and (6) of this section.

(1) A monitoring survey of each collection of fugitive emissions components at a well site within a company-defined area must be conducted at the frequencies specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) At least semiannually for the 2-year period following the initial survey, then at least annually. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

(ii) At least annually for each collection of fugitive emissions components located at one of the types of well sites in paragraphs (g)(1)(ii)(A) through (B). Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

(A) A well site located on the Alaskan North Slope; or

(B) A well site with average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production, where boe equals cubic feet gas/5658.53.

(2) Except as provided herein, a monitoring survey of the collection of fugitive emissions components at a compressor station within a company-defined area must be conducted at least quarterly after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 days apart. Each compressor must be monitored while in operation (*i.e.*, not in stand-by mode) at least annually. 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.

(3) Fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than 2 meters above the surface may be designated as difficult-to-monitor. Fugitive emissions components that are designated difficult-to-monitor must meet the specifications of paragraphs (g)(3)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated difficult-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as difficult-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as difficult-to-monitor is difficult-to-monitor.

(iv) The plan must include a schedule for monitoring the difficult-to-monitor fugitive emissions components at least once per calendar year.

(4) Fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor. Fugitive emissions components that are designated unsafe-to-monitor must meet the specifications of paragraphs (g)(4)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated unsafe-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as unsafe-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as unsafe-to-monitor is unsafe-to-monitor.

(iv) The plan must include a schedule for monitoring the fugitive emissions components designated as unsafe-to-monitor.

(5) The requirements of paragraph (g)(2) of this section are waived for any collection of fugitive emissions components at a compressor station located within an area that has an average calendar month temperature below 0° Fahrenheit for two of three consecutive calendar months of a quarterly monitoring period. The calendar month temperature average for each month within the quarterly monitoring period must be determined using historical monthly average temperatures over the previous three years as reported by a National Oceanic and Atmospheric Administration source or other source approved by the Administrator. The requirements of

paragraph (g)(2) of this section shall not be waived for two consecutive quarterly monitoring periods.

(6) 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) Each identified source of fugitive emissions shall be repaired as soon as practicable, but no later than 60 calendar days after detection of the fugitive emissions.

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

(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, well shutdown, well shut-in, after a scheduled vent blowdown or within 2 years, whichever is earlier. For purposes of this requirement, 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 repaired fugitive emissions component must be resurveyed 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 repaired fugitive emissions components using either Method 21 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, must clearly identify the component by location within the site (e.g., the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

(iii) Operators that use Method 21 to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in paragraphs (h)(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 are used.

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

(iv) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (h)(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.

(i) Records for each monitoring survey shall be maintained as specified §60.5420a(c)(15).

(j) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that include the information specified in §60.5420a(b)(7). Multiple collection of fugitive emissions components at a well site or at a compressor station may be included in a single annual report.

EFFECTIVE DATE NOTE: At 82 FR 25733, June 5, 2017, §60.5397a was stayed until Aug. 31, 2017.[81 FR 35898, June 3, 2016, as amended at 83 FR 10638, Mar. 12, 2018]

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

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in GHG (in the form of a limitation on emission of methane) and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under §60.5375a, §60.5385a, and §60.5397a, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with §60.5375a, §60.5385a, and §60.5397a. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

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

(c) The Administrator will consider applications under this section from owners or operators of affected facilities, and manufacturers or vendors of leak detection technologies, or trade associations provided they are submitted in conjunction with an owner or operator.

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

(1) The applicant must provide information that is sufficient for demonstrating the equivalence of the alternative means of emission limitation. At a minimum, the applicant must collect, verify, and submit field data to demonstrate the equivalence of the alternative means of emission limitation; the field data must encompass seasonal variations over the year to ensure that the technique works appropriately in different conditions that will be encountered during monitoring surveys. The field data may be supplemented with modeling analyses, test data, or other documentation. The application must include the following information:

(i) A description of the technology, technique, or process.

(ii) A description of the monitoring instrument or measurement technology used in the technology, technique, or process.

(iii) A description of performance based procedures (i.e., method) and data quality indicators for precision and bias; the method detection limit of the technology, technique, or process.

(iv) For affected facilities under §60.5397a, the action criteria and level at which a fugitive emission exists.

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

(vi) Timeframes for conducting ongoing quality assurance/quality control.

(vii) Field data verifying viability and detection capabilities of the technology, technique, or process. Test data, modeling analyses, or other documentation may be used to supplement field data.

(viii) Frequency of measurements and surveys conducted with the technology, technique, or process.

(ix) For continuous monitoring techniques, the minimum data availability.

(x) Sufficient data and other supporting documentation for determining the emissions reductions achieved or avoided by the technology, technique, or process.

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

(xii) Operation and maintenance procedures and other provisions necessary to ensure reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under §60.5397a.

(xiii) Initial and continuous compliance procedures, including recordkeeping and reporting, if the compliance procedures are different than those specified in §60.5397a(d).

(2) For each determination of equivalency requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated by field data, which can be supplemented with modeling analyses at an active production site or test data at a controlled test environment or facility.

(3) For each technology, technique, or process for which a determination of equivalency is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.

(e) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the FEDERAL REGISTER.

(f)(1) An application submitted under this section will be evaluated based on the field data, modeling analyses, and other documentation that was provided to demonstrate the equivalence of the alternative means of emission limitation under this section.

(2) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure that equivalent emission reductions are achieved.

(2) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure that sufficient emission reductions are achieved for satisfying the requirement for equivalency.

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

§60.5399a 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 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 (g) through (m) 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.

(a) The Administrator will consider applications for alternative fugitive emissions standards based on equivalent state, local, or tribal program under this section from any interested person, which includes, but is not limited to individuals, corporations, partnerships, associations, state, or municipalities.

(b) 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.

(c) After notice and opportunity for public comment, the Administrator will determine the equivalence of an alternative fugitive emissions standard and will publish the determination in the **Federal Register**.

(d)(1) An application submitted under this section will be evaluated based on the documentation that was provided to demonstrate the equivalence of the alternative fugitive emissions standards under this section.

(2) The Administrator may condition the approval of the alternative fugitive emissions standards on requirements that may be necessary to ensure that equivalent emissions reductions are achieved.

(e) 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) may be used by any owner or operator in meeting the relevant standards and requirements established for affected facilities under §60.5397a.

(f)(1) An owner or operator must notify the Administrator before implementing one of the alternative fugitive emissions standards, as specified in §60.5420a(a)(3).

(2) An owner or operator implementing one of the alternative fugitive emissions standards must include the information specified in §60.5420a(b)(7) in the annual report and maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

(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 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 and GHG emissions through compliance with the monitoring, repair, and recordkeeping requirements in the California Code of Regulations, title 17, §§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) of this subpart.

(h) *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, §§XII.L, effective June 30, 2018, or XVII.F, effective October 15, 2014 for well sites and January 1, 2015 for compressor stations, as an alternative to complying with the requirements in §60.5397a(f)(1) and (2), (g)(1) through (4), (h), and (i) of this subpart, provided the monitoring instrument used is OGI or a Method 21 instrument.

(i) *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) of this subpart, provided the leak definition used is Method 21 monitoring with an instrument reading of 500 ppm or greater.

(j) *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)

of this subpart, provided the leak definition used is Method 21 monitoring with an instrument reading of 500 ppm or greater.

(k) *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) of this subpart, provided the monitoring instrument used is OGI or a Method 21 instrument.

(l) *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) of this subpart, provided the monitoring instrument used is OGI or a Method 21 instrument.

(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 Tex. Admin. Code §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) of this subpart, provided the monitoring instrument used is a Method 21 instrument and that the leak definition used for Method 21 monitoring is an instrument reading of 2,000 ppm or greater.

(m) *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) of this subpart.

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

This section applies to the group of all equipment, except compressors, within a process unit.

(a) You must comply with the requirements of §§60.482-1a(a), (b), (d), and (e), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401a.

(b) You may elect to comply with the requirements of §§60.483-1a and 60.483-2a, as an alternative.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least

equivalent to that achieved by the controls required in this subpart according to the requirements of §60.5402a.

(d) You must comply with the provisions of §60.485a except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§60.486a and 60.487a except as provided in §§60.5401a, 60.5421a, and 60.5422a.

(f) You must use the following provision instead of §60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in §60.17) must be used.

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

(a) You may comply with the following exceptions to the provisions of §60.5400a(a) and (b).

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b)

except as provided in §60.5400a(c) and in paragraph (b)(4) of this section, and §60.482-4a(a) through (c) of subpart VVa of this part.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are onsite, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1).

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section may be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of §60.482-5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§60.482-2a(a)(1), 60.482-7a(a), 60.482-11a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the monitoring

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

(f) An owner or operator may use the following provisions instead of §60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

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

definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

§60.5402a What are the alternative means of emission limitations for GHG and VOC equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in GHG and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

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

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) An application submitted under paragraph (c) of this section must meet the following criteria:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) The application must include operation, maintenance and other provisions necessary to assure reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under the design, equipment, work practice or operational standard in paragraph (a) of this section by including the information specified in paragraphs (d)(1)(i) through (x) of this section.

(i) A description of the technology or process.

(ii) The monitoring instrument and measurement technology or process.

(iii) A description of performance based procedures (i.e. method) and data quality indicators for precision and bias; the method detection limit of the technology or process.

(iv) The action criteria and level at which a fugitive emission exists.

(v) Any initial and ongoing quality assurance/quality control measures.

(vi) Timeframes for conducting ongoing quality assurance/quality control.

(vii) Field data verifying viability and detection capabilities of the technology or process.

(viii) Frequency of measurements.

(ix) Minimum data availability.

(x) Any restrictions for using the technology or process.

(3) The application must include initial and continuous compliance procedures including recordkeeping and reporting.

§60.5405a What standards apply to sweetening unit affected facilities at onshore natural gas processing plants?

(a) During the initial performance test required by §60.8(b), you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

§60.5406a What test methods and procedures must I use for my sweetening unit affected facilities at onshore natural gas processing plants?

(a) In conducting the performance tests required in §60.8, you must use the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) During a performance test required by §60.8, you must determine the minimum required reduction efficiencies (Z) of SO_2 emissions as required in §60.5405a(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$$X = KQ_aY$$

Where:

X = average sulfur feed rate, Mg/D (LT/D).

Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).

Y = average H_2S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.

K = (32 kg S/kg-mole)/((24.04 dscm/kg-mole)(1000 kg S/Mg)).

= 1.331×10^{-3}Mg/dscm, for metric units.

= (32 lb S/lb-mole)/((385.36 dscf/lb-mole)(2240 lb S/long ton)).

= 3.707×10^{-5} long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in §60.5408a or a chromatographic procedure following ASTM E260-96 (incorporated by reference as specified in §60.17) to determine the

H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine compliance with the SO_2 standards in §60.5405a(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$R = (100S)/(S + E)$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage vessels. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$E = C_e Q_{sd}/K_1$

Where:

E = emission rate of sulfur per run, kg/hr.

C_e = concentration of sulfur equivalent (SO^{2+} reduced sulfur), g/dscm (lb/dscf).

Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2 and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of appendix A-1 of this part to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m^2 or more, and the centroid is more than 1 m (39 in) from the wall.

(i) You must use Method 6 of appendix A-4 of this part to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent. In place of Method 6 of Appendix A of this part, you may use ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17).

(ii) You must use Method 15 of appendix A-5 of this part to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft^3/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A of appendix A-6 of this part or Method 15 of appendix A-5 of this part or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by

reference as specified in §60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A-1 of this part to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

§60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

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

(1) The accumulation of sulfur product over each 24-hour period. The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels

with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ±2 percent of the 24-hour sulfur accumulation.

(2) The H_2S concentration in the acid gas from the sweetening unit for each 24-hour period. At least one sample per 24-hour period must be collected and analyzed using the equation specified in §60.5406a(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is within ±20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ±20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) The average acid gas flow rate from the sweetening unit. You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) The sulfur feed rate (X). For each 24-hour period, you must compute X using the equation specified in §60.5406a(b)(1).

(5) The required sulfur dioxide emission reduction efficiency for the 24-hour period. You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of §60.5405a(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere. The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405a(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with §60.5405a(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ±1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of §60.8 to demonstrate compliance with the standards under §60.5405a, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate

level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under §60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405a(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock

interval. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in §60.5406a(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

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Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

K_2 = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by §60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of §60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by §60.13(c), Performance Specification 2 of appendix B of this part must apply, and Method 6 of appendix A-4 of this part must be used for systems required by paragraph (b) of this section. In place of Method 6 of appendix A-4 of this part, ASME PTC 19.10-1981 (incorporated by reference—see §60.17) may be used.

§60.5408a What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A-80-20-A, Entry II-I-67).

(a) When an instantaneous sample is desired and H_2S concentration is 10 grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than 10 grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart.) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top that connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.* (1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide (KI) for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml=0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) Starch solution. Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) *Procedure*. Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine through (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then,

Grains H_2S per 100 cubic foot of gas = 100 (D-C)

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.

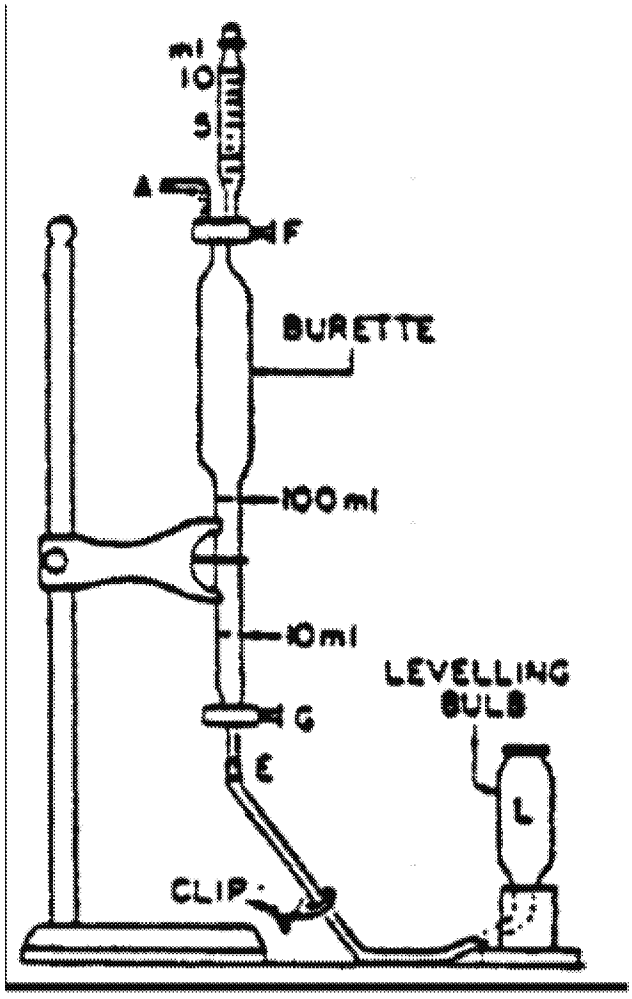

Figure 1. Tutwiler burette (lettered items mentioned in text).

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

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (j) of this section. The initial compliance period

begins on August 2, 2016, or upon initial startup, whichever is later, and ends no later than 1 year after the initial startup date for your affected facility or no later than 1 year after August 2, 2016. The initial compliance period may be less than one full year.

(a) To achieve initial compliance with the methane and VOC standards for each well completion operation conducted at your well affected facility you must comply with paragraphs (a)(1) through (4) of this section.

(1) You must submit the notification required in §60.5420a(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in §60.5420a(b)(1) and (2).

(3) You must maintain a log of records as specified in §60.5420a(c)(1)(i) through (iv), as applicable, for each well completion operation conducted during the initial compliance period. If you meet the exemption for wells with a GOR less than 300 scf per stock barrel of oil produced, you do not have to maintain the records in §60.5420a(c)(1)(i) through (iv) and must maintain the record in §60.5420a(c)(1)(vi).

(4) For each well affected facility subject to both §60.5375a(a)(1) and (3), as an alternative to retaining the records specified in §60.5420a(c)(1)(i) through (iv), you may maintain records in accordance with §60.5420a(c)(1)(v) of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment

connected and operating at each well completion operation with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(b)(1) To achieve initial compliance with standards for your centrifugal compressor affected facility you must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required by §60.5380a(a) and as demonstrated by the requirements of §60.5413a.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411a(b) that is connected through a closed vent system that meets the requirements of §60.5411a(a) and (d) and is routed to a control device that meets the conditions specified in §60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

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

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

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

(6)]Reserved]

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in §60.5420a(b)(1) and (3).

(8) You must maintain the records as specified in §60.5420a(c)(2), (6) through (11), and (17), as applicable.

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

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

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

(3) You must submit the initial annual report for your reciprocating compressor as required in §60.5420a(b)(1) and (4).

(4) You must maintain the records as specified in §60.5420a(c)(3) for each reciprocating compressor affected facility.

(d) To achieve initial compliance with methane and VOC emission standards for your pneumatic controller affected facility you must comply with the requirements specified in paragraphs (d)(1) through (6) of this section, as applicable.

(1) You must demonstrate initial compliance by maintaining records as specified in §60.5420a(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required as specified in §60.5390a(b)(1) or (c)(1).

(2) If you own or operate a pneumatic controller affected facility located at a natural gas processing plant, your pneumatic controller must be driven by a gas other than natural gas, resulting in zero natural gas emissions.

(3) If you own or operate a pneumatic controller affected facility located other than at a natural gas processing plant, the controller manufacturer's design specifications for the controller must indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

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

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of §60.5420a(b)(1) and (5).

(6) You must maintain the records as specified in §60.5420a(c)(4) for each pneumatic controller affected facility.

(e) To achieve initial compliance with emission standards for your pneumatic pump affected facility you must comply with the requirements specified in paragraphs (e)(1) through (7) of this section, as applicable.

(1) If you own or operate a pneumatic pump affected facility located at a natural gas processing plant, your pneumatic pump must be driven by a gas other than natural gas, resulting in zero natural gas emissions.

(2) If you own or operate a pneumatic pump affected facility located at a well site, you must reduce emissions in accordance with §60.5393a(b)(1) or (b)(2), and you must collect the

pneumatic pump emissions through a closed vent system that meets the requirements of §60.5411a(c) and (d).

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

(5) If you own or operate a pneumatic pump affected facility 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(c) and (d).

(6) You must submit the initial annual report for your pneumatic pump affected facility required in §60.5420a(b)(1) and (8).

(7) You must maintain the records as specified in §60.5420a(c)(6), (8) through (10), (16), and (17), as applicable, for each pneumatic pump affected facility.

(8) [Reserved]

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the methane and VOC standards is demonstrated if you are in compliance with the requirements of §60.5400a.

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

(1) To determine compliance with the standards for SO_2 specified in §60.5405a(a), during the initial performance test as required by §60.8, the minimum required sulfur dioxide emission

reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406a(c)(1).

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

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

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

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

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

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

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

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

(i) For each storage vessel affected facility that complies by using a floating roof, you must submit a statement that you are complying with §60.112(b)(a)(1) or (2) in accordance with §60.5395a(b)(2) with the initial annual report specified in §60.5420a(b).

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

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

(2) You must conduct an initial monitoring survey as required in §60.5397a(f).

(3) You must maintain the records specified in §60.5420a(c)(15).

(4) You must repair each identified source of fugitive emissions for each affected facility as required in §60.5397a(h).

(5) You must submit the initial annual report for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station compressor station as required in §60.5420a(b)(1) and (7).

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

EFFECTIVE DATE NOTE: At 82 FR 25733, June 5, 2017, in §60.5410a, paragraphs (e)(2) through (5) and paragraph (j) were stayed until Aug. 31, 2017.

§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).

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by §60.5416a(b).

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

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

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in §60.5416a(a)(4)(i) and sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420a(c)(8).

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

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

(b) Cover requirements for storage vessels and centrifugal compressor wet seal fluid degassing systems.

(1) The cover and all openings on the cover (*e.g.*, access hatches, sampling ports, pressure relief devices and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (a) or (c), and (d), of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(c) Closed vent system requirements for storage vessel and 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 material in the storage vessel or pneumatic pump to a control device or to a process. For storage vessels, the closed vent system must route all gases, vapors, and fumes to a control device that meets the requirements specified in §60.5412a(c) and (d).

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections.

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

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

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

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

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

(d) Closed vent systems requirements for centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels using a control device or routing emissions to a process.

(1) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the 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 an in-house engineer or a qualified professional engineer in accordance with paragraphs (d)(1)(i) and (ii) of this section.

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

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

(2) [Reserved]

(e) [Reserved]

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

EFFECTIVE DATE NOTE: At 82 FR 25733, June 5, 2017, in §60.5411a, paragraph (d) was stayed until Aug. 31, 2017.

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

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

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

(1) Each combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section. 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.

(i) You must reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413a(b), with the exceptions noted in §60.5413a(a).

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of §60.5413a(b), with the exceptions noted in §60.5413a(a).

(iii) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under §60.5413a(b), that combustion zone temperature is an indicator of destruction efficiency.

(iv) 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.

(2) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413a(b). As an alternative to the performance testing requirements, you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of §60.5413a(c).

(3) You must design and operate a flare in accordance with the requirements of §60.18(b), and you must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(b) You must operate each control device installed on your centrifugal compressor affected facility in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system affected facility as required under §60.5380a(a)(1) through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of §60.5417a(a) through (g), you must demonstrate compliance according to the requirements of §60.5415a(b)(2), as applicable.

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

(1) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to §60.5413a(c)(2) or (3) or according to the design required in paragraph (d)(2) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in §60.5420a(c)(10) and (12).

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vi) of this section.

(i) Regenerate or reactivate the spent carbon in a unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a unit equipped with an operating organic air emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 63 or this part.

(iii) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(iv) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(v) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vi) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(d) Each control device used to meet the emission reduction standard in §60.5395a(a)(2) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (4) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under §60.5413a(d), which meets the criteria in §60.5413a(d)(11) and meet the continuous compliance requirements in §60.5413a(e).

(1) For each combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.

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

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

(iii) Operate the combustion control device with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22 of appendix A-7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair

activity, each device must pass a Method 22 of appendix A-7 of this part visual observation as described in this paragraph.

(iv) Each enclosed combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (A) through (D) of this section. 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.

(A) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413a(b).

(B) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of §60.5413a(b).

(C) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under §60.5413a(b), that combustion zone temperature is an indicator of destruction efficiency.

(D) 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.

(2) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(3) You must design and operate a flare in accordance with the requirements of §60.18(b), and you must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(4) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

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

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your centrifugal compressor affected facility or storage vessel affected facility. You must demonstrate that a control device achieves the performance requirements of §60.5412a(a)(1) or (2) or (d)(1) or (2) using the performance test methods and procedures specified in this section. For condensers and carbon adsorbers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion control device performance tests conducted by the manufacturer applicable to storage vessel and centrifugal compressor affected facilities.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) A flare that is designed and operated in accordance with §60.18(b). You must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H; you have submitted a Notification of Compliance under 40 CFR 63.1207(j) and comply with the requirements of 40 CFR part 63, subpart EEE; or you comply with 40 CFR part 63, subpart EEE and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in §60.5420(b)(9) for submitting the initial performance test report.

(5) A hazardous waste incinerator for which you have submitted a Notification of Compliance under 40 CFR 63.1207(j), or for which you will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in §60.5420a(b)(9) for submitting the initial performance test report, and you comply with the requirements of 40 CFR part 63, subpart EEE.

(6) A performance test is waived in accordance with §60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of §60.5412a(a)(1) or (d)(1) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of §60.5412a(a)(1) or (2) or (d)(1) or (2). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section. Each performance test must consist of a minimum of 3 test runs. Each run must be at least 1 hour long.

(1) You must use Method 1 or 1A of appendix A-1 of this part, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device and at the outlet of the final control device to determine compliance with a control device percent reduction requirement.

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with a TOC exhaust gas concentration limit.

(2) You must determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of appendix A-2 of this part, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in §60.5412a(a)(1)(i), (a)(2) or (d)(1)(iv)(A), you must use Method 25A of appendix A-7 of this part. You must use Method 4 of appendix A-3 of this part to convert the Method 25A results to a dry basis. You must use the procedures in paragraphs (b)(3)(i) through (iii) of this section to calculate percent reduction efficiency.

(i) You must compute the mass rate of TOC using the following equations:

$E_i = K_2 C_i M_p Q_i$

$E_o = K_2 C_o M_p Q_o$

Where:

E_i, E_o = Mass rate of TOC at the inlet and outlet of the control device, respectively, dry basis, kilograms per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 °Celsius.

C_i, C_o = Concentration of TOC, as propane, of the gas stream as measured by Method 25A at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_p = Molecular weight of propane, 44.1 gram/gram-mole.

Q_i, Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

(ii) You must calculate the percent reduction in TOC as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

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Where:

R_{cd} = Control efficiency of control device, percent.

E_i, = Mass rate of TOC at the inlet to the control device as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

E_o = Mass rate of TOC at the outlet of the control device, as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

(iii) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC across the device by comparing the TOC in all combusted vent streams and primary and secondary fuels with the TOC exiting the device, respectively.

(4) You must use Method 25A of appendix A-7 of this part to measure TOC, as propane, to determine compliance with the TOC exhaust gas concentration limit specified in §60.5412a(a)(1)(ii) or (d)(1)(iv)(B). You may also use Method 18 of appendix A-6 of this part to measure methane and ethane. You may subtract the measured concentration of methane and ethane from the Method 25A measurement to demonstrate compliance with the concentration limit. You must determine the concentration in parts per million by volume on a wet basis and correct it to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) If you use Method 18 to determine methane and ethane, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run. You must determine the average methane and ethane concentration per run. The samples must be taken during the same time as the Method 25A sample.

(ii) You may subtract the concentration of methane and ethane from the Method 25A TOC, as propane, concentration for each run.

(iii) You must correct the TOC concentration (minus methane and ethane, if applicable) to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B of appendix A-2 of this part, ASTM D6522-00

(Reapproved 2011), or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m\left(\frac{17.9}{20.9 - \%O_{2m}}\right)$$

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Where:

C_c = TOC concentration, as propane, corrected to 3 percent oxygen, parts per million by volume on a wet basis.

C_m = TOC concentration, as propane, (minus methane and ethane, if applicable), parts per million by volume on a wet basis.

$\%O_{2m}$ = Concentration of oxygen, percent by volume as measured, wet.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in §60.5420a(b)(9).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic

performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in §60.5420a(b)(9).

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section. For centrifugal compressor affected facilities, if you do not continuously monitor the gas flow rate in accordance with §60.5417a(d)(1)(viii), then you must comply with the periodic performance testing requirements of paragraph (b)(5)(ii).

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in §60.5412a(a)(1)(ii) or (d)(1)(iv)(B) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level. For centrifugal compressor affected facilities, you must establish a limit on temperature in accordance with §60.5417a(f) and continuously monitor the temperature as required by §60.5417a(d).

(c) *Control device design analysis to meet the requirements of §60.5412a(a)(2) or (d)(2).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete

carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems shall incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

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

(2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a

total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

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

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

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

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

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device

operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

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

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

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

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

(i) At the inlet gas sampling location, securely connect a 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.

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

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

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

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

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945-03 (incorporated by reference as specified in §60.17).

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945-03 (incorporated by reference as specified in §60.17).

(C) Higher heating value using ASTM D3588-98 or ASTM D4891-89 (incorporated by reference as specified in §60.17).

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

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) and (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using Method 1 of appendix A-1 of this part for determining flow measurement traverse point location, and Method 2 of appendix A-1 of this part for measuring duct velocity. If low flow conditions are encountered (*i.e.*, velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

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

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

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

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

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

(i) An integrated bag sample must be collected during the moisture test required by Method 4 of appendix A-3 of this part following the procedure specified in (d)(7)(i)(A) and (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC-TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) and (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC-TCD calibration procedure in Method 3C of appendix A-2 of this part must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using Method 4 of appendix A-3 of this part. Traverse both ports with the sampling train required by Method 4 of appendix A-3 of this part during each test run. Ambient air must not be introduced into the integrated bag sample required by Method 3C of appendix A-2 of this part during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B of appendix A-2 of this part, equation 3B-1, or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17).

(8) Carbon monoxide must be determined using Method 10 of appendix A-4 of this part. Run the test simultaneously with Method 25A of appendix A-7 of this part using the same sampling points. An instrument range of 0-10 parts per million by volume-dry (ppmvd) is recommended.

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

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

(ii) A valid test must consist of three Method 25A tests, each no less than 60 minutes in duration.

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

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—"EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," (incorporated by reference as specified in §60.17).

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO_2, as measured by Method 3C of appendix A-2 of this part. You must use the following equation for this diluent concentration correction:

$$C_{corr} = C_{meas}\left(\frac{3}{CO_{2meas}}\right)$$

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Where:

C_{meas} = The measured concentration of the pollutant.

CO_{2meas} = The measured concentration of the CO_2 diluent.

3 = The corrected reference concentration of CO_2 diluent.

C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using Method 22 of appendix A-7 of this part. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Results from Method 22 of appendix A-7 of this part determined under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average results from Method 25A of appendix A-7 of this part determined under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2.

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

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

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

(iii) A manufacturer must demonstrate a destruction efficiency of at least 95 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95 percent for THC, as propane, will meet the control requirement for 95 percent destruction of VOC and methane (if applicable) required under this subpart.

(12) The owner or operator of a combustion control device model tested under this paragraph must submit the information listed in paragraphs (d)(12)(i) through (vi) of this section 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) CBIO Room 521; 109 T.W. Alexander Drive; RTP, NC 27711. The same file with the CBI omitted must be submitted to *Oil_and_Gas_PT@EPA.GOV*.

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess air range.

(G) Flame arrestor(s).

(H) Burner manifold.

(I) Pilot flame indicator.

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

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

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

(e) *Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph (e) applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance criteria in paragraph (d)(11) of this section by installing a device tested under paragraph (d) of this section, complying with the criteria specified in paragraphs (e)(1) through (8) of this section, maintaining the records specified in §60.5420a(c)(2) or (c)(5)(vi) and submitting the report specified in §60.5420a(b)(10).

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to

section 11 of EPA Method 22 of appendix A-7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass a visual observation according to EPA Method 22 of appendix A-7 of this part as described in paragraph (e)(3) of this section.

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

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

(8) Operate each control device following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

§60.5415a How do I demonstrate continuous compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, and collection of

fugitive emissions components at a compressor station affected facilities, and affected facilities at onshore natural gas processing plants?

(a) For each well affected facility, you must demonstrate continuous compliance by submitting the reports required by §60.5420a(b)(1) and (2) and maintaining the records for each completion operation specified in §60.5420a(c)(1).

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

(1) You must reduce methane and VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of §60.5412a(a) using the procedures specified in paragraphs (b)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in §60.5412a(a)(2), you may demonstrate compliance according to paragraph (b)(2)(viii) of this section. You may switch between compliance with paragraphs (b)(2)(i) through (vii) of this section and compliance with paragraph (b)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, following the change.

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

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with §60.5417a(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (b)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (b)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in §60.5413a(d), compliance with the operating parameter limit is achieved when the criteria in §60.5413a(e) are met.

(iv) You must operate the continuous monitoring system required in §60.5417a(a) at all times the affected source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You

must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of §60.5412a(a)(1) and you demonstrate compliance using the test procedures specified in §60.5413a(b), or you use a flare designed and operated in accordance with §60.18(b), you must comply with paragraphs (b)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 of this part visual observation as described in paragraph (b)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in §60.5412a(a)(2), you must demonstrate compliance using the procedures in paragraphs (b)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to §60.5417a(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with §60.5417a(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (b)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (b)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (b)(2)(viii)(D)(*1*) and (*2*) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (b)(2)(viii)(C) of this section.

(*1*) After the compliance dates specified in §60.5370a(a), if you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation after the compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(*2*) After 120 days and no more than 364 days of operation after the compliance date specified in §60.5370a(a), you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (b)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

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

(4) [Reserved]

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

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

(2) You must submit the annual reports as required in §60.5420a(b)(1) and (4) and maintain records as required in §60.5420a(c)(3).

(3) You must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) You must operate the rod packing emissions collection system under negative pressure and continuously comply with the cover and closed vent requirements in §60.5416a(a) and (b).

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in §60.5390a(a), (b), or (c).

(2) You must submit the annual reports as required in §60.5420a(b)(1) and (5).

(3) You must maintain records as required in §60.5420a(c)(4).

(e) You must demonstrate continuous compliance according to paragraph (e)(3) of this section for each storage vessel affected facility, for which you are using a control device or routing emissions to a process to meet the requirement of §60.5395a(a)(2).

(1)-(2) [Reserved]

(3) For each storage vessel affected facility, you must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) You must reduce VOC emissions as specified in §60.5395a(a)(2).

(ii) For each control device installed to meet the requirements of §60.5395a(a)(2), you must demonstrate continuous compliance with the performance requirements of §60.5412a(d) for each storage vessel affected facility using the procedure specified in paragraph (e)(3)(ii)(A) and either (e)(3)(ii)(B) or (e)(3)(ii)(C) of this section.

(A) You must comply with §60.5416a(c) for each cover and closed vent system.

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

(C) Each closed vent system that routes emissions to a process must be operated as specified in §60.5411a(c)(2) and (3).

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with methane and VOC requirements is demonstrated if you are in compliance with the requirements of §60.5400a.

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

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406a(c)(1).

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

(1) You must conduct periodic monitoring surveys as required in §60.5397a(g).

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

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

(4) You must submit annual reports for collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in §60.5420a(b)(1) and (7).

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

EFFECTIVE DATE NOTE: At 82 FR 25733, June 5, 2017, in §60.5415a, paragraph (h) was stayed until Aug. 31, 2017.

§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 (c) of this section.

(a) Inspections for closed vent systems and covers installed on each centrifugal compressor or reciprocating compressor affected facility. Except as provided in paragraphs (b)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(ii) Conduct annual inspections according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections;

liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(3) For each cover, you must meet the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) You must initially conduct the inspections specified in paragraph (a)(3)(i) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (b)(11) and (12) of this section. You must maintain records of the inspection results as specified in §60.5420a(c)(7).

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

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the

non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to §60.5420a(c)(8).

(b) No detectable emissions test methods and procedures. If you are required to conduct an inspection of a closed vent system or cover at your centrifugal compressor, reciprocating compressor, or pneumatic pump affected facility as specified in paragraphs (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21 of appendix A-7 of this part.

(2) The detection instrument must meet the performance criteria of Method 21 of appendix A-7 of this part, except that the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 of appendix A-7 of this part.

(4) Calibration gases must be as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 of appendix A-7 of this part.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (b)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 of appendix A-7 of this part, except the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (b)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (b)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (b)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (b)(9)(i) and (ii) of this section, except as provided in paragraph (b)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (b)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (b)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records.* Records shall be maintained as specified in this section and in §60.5420a(c)(9).

(c) *Cover and closed vent system inspections for pneumatic pump or 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 (c)(2) of this section. You must also comply with the requirements of (c)(3) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection at least once every calendar month as specified in paragraphs (c)(1)(i) through (iii) of this section.

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

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

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

(2) For each cover, you must conduct inspections at least once every calendar month as specified in paragraphs (c)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in §60.5420a(c)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

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

(3) For each bypass device, except as provided for in §60.5411a(c)(3)(ii), you must meet the requirements of paragraphs (c)(3)(i) or (ii) of this section.

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

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the

non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to §60.5420a(c)(8).

(4) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (c)(4)(i) through (iii) of this section, except as provided in paragraph (c)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (c)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (c)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (c)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(d) [Reserved]

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

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

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

(a) For each control device used to comply with the emission reduction standard for centrifugal compressor affected facilities in §60.5380a(a)(1), you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with §60.5412a(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section. If you install and operate an enclosed combustion device 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 (h)(4) of this section.

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

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan. Heat sensing monitoring devices that indicate the

continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under §60.5413a(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame. The heat sensing monitoring device is exempt from the calibration requirements of this section.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the

temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater.

(vii) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in §60.5413a(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under §60.5413a(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of

this section. If you comply with the periodic testing requirements of §60.5413a(b)(5)(ii), you are not required to continuously monitor the gas flow rate under paragraph (d)(1)(viii)(A) of this section.

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better at the maximum expected flow rate. The flow rate at the inlet to the combustion device must not exceed the maximum flow rate determined by the manufacturer.

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

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

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in §60.13(i).

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate and data from the heat sensing devices that indicate the presence of a pilot flame. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device

operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of §60.5412a(a)(1) or (2). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of §60.5413a(b) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412a(a)(1) or (2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of §60.5413a(c) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412a(a)(2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under §60.5413a(d) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412a(a)(1), then your control device inlet gas flow rate must not exceed the maximum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of §60.5413a(b) to demonstrate that the condenser achieves the applicable performance requirements in §60.5412a(a)(2), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of §60.5413a(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in §60.5412a(a)(2), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this

section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section or when the heat sensing device indicates that there is no pilot flame present.

(2) If you are subject to §60.5412a(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in §60.5415a(b)(2)(viii)(D) is less than 95.0 percent.

(3) If you are subject to §60.5412a(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in §60.5415a(b)(2)(viii)(D)(*1*) or (*2*) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraph (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to §60.5411a(a)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to §60.5411a(a)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under §60.5413a(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) of this section are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under §60.5413a(d).

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

(h) For each control device used to comply with the emission reduction standard in §60.5395a(a)(2) for your storage vessel affected facility, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(4) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with §60.5413a(d)(2) through (10), which meets the criteria in §60.5413a(d)(11), the reporting requirement in §60.5413a(d)(12), and meet the continuous compliance requirement in §60.5413a(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (h)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22 of appendix A of this part. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

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

(iv) For any absence of the pilot flame, or other indication of smoking or improper equipment operation (*e.g.*, visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (h)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified in §60.5420a(c)(13).

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in §60.5413a(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

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

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

(1) If you own or operate an affected facility that is the group of all equipment within a process unit at an onshore natural gas processing plant, or a sweetening unit at an onshore natural gas processing plant, you must submit the notifications required in §60.7(a)(1), (3), and (4) and §60.15(d). If you own or operate a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, or collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station, you are not required to submit the notifications required in §60.7(a)(1), (3), and (4) 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 standard selected 90 days before implementing any of the provisions.

(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 for all reports.

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

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

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

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

(2) For each well affected facility 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 (b)(2)(xiv) of this section, if applicable. In lieu of submitting the records specified in paragraph (b)(2)(i) through (b)(2)(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 permanent separators, the records specified in paragraphs (b)(2)(i) through (b)(2)(iv) and (b)(2)(vi) through (b)(2)(xiv) of this section. For each well affected facility that is subject to §60.5375a(g), the record specified in paragraph (b)(2)(xv) of this section.

(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) US Well ID.

(iv) The date and time of the onset of flowback following hydraulic fracturing or refracturing

(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, how the defect or leak was repaired and 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 §60.5413a(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 later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

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

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

(vii) 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 §60.5413a(e), the information in paragraphs (b)(6)(vii)(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.

(viii) 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.

(ix) If required to comply with §60.5395a(b)(1), the information in paragraphs (b)(6)(ix)(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, how the defect or leak was repaired 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).

(7) For the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each compressor station within the company-defined area, the information specified in paragraphs (b)(7)(i) and (ii) of this section.

(i)(A) 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.

(B) 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 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 a statement that all major production and processing equipment has been removed from the well site, the date of the removal of the last piece of major production and processing equipment, and if the well site is still producing to another site, the well ID or separate tank battery ID receiving the production.

(D) For each collection of fugitive emissions components at a well site where you previously reported under paragraph (b)(7)(i)(C) 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.

(E) For the collection of fugitive emissions components at a compressor station, if a monitoring survey is waived under §60.5397a(g)(5), you must include in your annual report the fact that a monitoring survey was waived and the calendar months that make up the quarterly monitoring period for which the monitoring survey was waived.

(F) For each new collection of fugitive emissions components at a well site where the average combined oil and natural gas production for the wells at the site is less than 15 boe per day, you must submit the combined oil and natural gas production in boe for the wells at the site, averaged over the first 30 days of production.

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

(A) Date of the survey.

(B) Name or unique ID of operator(s) performing survey.

(C) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(D) Monitoring instrument used.

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

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

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

(H) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(I) The date of successful repair of the fugitive emissions component.

(J) Number and type of fugitive emission components currently on delay of repair and explanation for each delay of repair.

(K) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding, if the type of instrument is different from the type used during the initial fugitive emissions finding.

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

(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 paragraphs (b)(8)(i)(A), (B) or (C) of this section.

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

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

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

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

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

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

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

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

(iii) 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(c);

(B) Each defect or leak identified during each inspection, how the defect or leak was repaired 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 Web site (*G:\USER\SHARE_FIG\Oil & Gas\NSPS 3.0 Reconsiderations\Technical 5719.8\OMB Package*) at the time of the test, you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used

electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

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

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

(11) You must submit reports to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX (https://cdx.epa.gov/).) You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (https://www3.epa.gov/ttn/chief/cedri/). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The reports must be submitted by the deadlines specified in this subpart, regardless of the method in which the reports are submitted. If you claim that some of the information required to be submitted via CEDRI is CBI, 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 Web site, 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, Measurement Policy 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.

(12) You must submit the certification signed by the in-house engineer or qualified professional 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, and due to a planned or actual outage of either the EPA's CEDRI or CDX systems within the period of time beginning 5 business days prior to the date that the submission is due, you will be or are precluded from accessing CEDRI or CDX and submitting a required report within the time prescribed, you may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. 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. You must provide to the Administrator a written description identifying the date, time and length of the outage; a rationale for attributing the delay in reporting beyond the regulatory deadline to the EPA system outage; describe the measures taken or to be taken to minimize the delay in reporting; and identify a 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. In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved. 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.

(14) If you are required to electronically submit a report through CEDRI in the EPA's CDX and a force majeure event is about to occur, occurs, or has occurred within the period of time beginning 5 business days prior to the date the submission is due, the owner or operator may assert a claim of force majeure for failure to timely comply with the reporting requirement. 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). If you intend to assert a claim of force majeure, 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. You must provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event; describe the measures taken or to be taken to minimize the delay in reporting; and identify a 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. In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs. 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.

(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), only. For each well affected facility that routes flowback entirely through permanent separators the date and time of each attempt to direct flowback to a separator is not 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 that subparagraph.

(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(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 §60.5413a(e) and used to comply with §60.5380a(a)(1) for each centrifugal compressor.

(i) Make, model and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) Location of the centrifugal compressor and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in §60.5413a(e) as specified in paragraphs (c)(2)(vi)(A) through (E) of this section.

(A) Records that the pilot flame is present at all times of operation.

(B) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(C) Records of the maintenance and repair log.

(D) Records of the visible emissions test following return to operation from a maintenance or repair activity, 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 later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

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

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in §60.5385a, 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), 60.5416a(c)(6)(ii), and 60.5416a(c)(7)(ii). You must maintain the records in paragraph (c)(5)(vi) of this part for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5395a(a)(2) for each storage vessel.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under §60.5365a(e) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) 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 oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment. If a storage vessel is removed from a site and, within 30 days, is either returned to the site or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the

original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(v) You must maintain records of the identification and location 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 §60.5413a(e) and used to comply with §60.5395a(a)(2) for each storage vessel.

(A) Make, model and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in §60.5413a(e) as specified in paragraphs (c)(5)(vi)(F)(*1*) through (*5*) of this section.

(*1*) Records that the pilot flame is present at all times of operation.

(*2*) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(*3*) Records of the maintenance and repair log.

(*4*) Records of the visible emissions test following return to operation from a maintenance or repair activity, 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) for centrifugal compressors and reciprocating compressors, or §60.5416a(c)(1) for storage vessels and pneumatic pumps as required in paragraphs (c)(6)(i) through (iii) of this section.

(i) A record of each closed vent system inspection. 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 detected during inspections required by §60.5416a(a)(1) and (2) or §60.5416a(c)(1), 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), 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 or pneumatic pumps as required in paragraphs (c)(7)(i) through (iii) of this section.

(7) The records for the cover inspection required under §60.5416a(a)(3) for centrifugal or reciprocating compressors or §60.5416a(c)(2) or (d)(3) for storage vessels or pneumatic pumps, 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 §60.5416a(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), 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) If you are subject to the closed vent system no detectable emissions requirements of §60.5416a(b) for centrifugal compressors or reciprocating compressors, you must prepare and maintain the records required in paragraphs (c)(9)(i) through (iii) of this section.

(i) A record of each closed vent system 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 monitoring survey.

(ii) For each leak detected during inspections required by §60.5416a(b), you must record the location of the leak, the maximum concentration reading obtained using Method 21, the date of detection, the corrective action taken the repair the leak, and the date the repair to correct the leak is completed.

(iii) If repair of the leak 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.

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

(11) For each centrifugal compressor affected facility subject to the control device requirements of §60.5412a(a), (b), and (c), records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of

continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(12) For each carbon adsorber installed on storage vessel affected facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of §60.5412a(d)(2)) and records of each carbon replacement as specified in §60.5412a(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of §60.5412a(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in §60.5417a(h)(3). You must maintain records of EPA Method 22 of appendix A-7 of this part, section 11 results, which include: Company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in EPA Method 22 of appendix A-7 of this part. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

(14) A log of records as specified in §60.5412a(d)(1)(iii), for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

(15) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, the records identified in paragraphs (c)(15)(i) through (vii) 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 compressor station.

(ii) 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, 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, 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, the date that the first piece of major production and processing equipment is added back to the well site.

(iii) For each collection of fugitive emissions components at a well site that is monitored annually under (g)(1)(ii)(B), the records identified in paragraphs (c)(15)(iii)(A) and (B) of this section.

(A) The average daily combined oil and natural gas production for the well site during the first 30 days of production; and

(B) A description of the methodology used to calculate the daily average production for the well site.

(iv) The fugitive emissions monitoring plan as required in §60.5397a(b), (c), and (d).

(v) The records of each monitoring survey as specified in paragraphs (c)(15)(v)(A) through (L) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s) performing survey. If you choose to report the unique ID of the operator(s) performing the survey in lieu of the operator(s) name, you must keep a record linking

the unique ID to the operator(s) name. You must note the training and experience of the operator(s).

(D) Monitoring instrument used.

(E) When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used for conduct of monitoring, of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital file, the digital photograph or video may consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided the latitude and longitude output of the GPS unit can be clearly read in the digital image. Digital photographs or video recorded under paragraph (c)(15)(v)(K)(*1*) of this section can be used to meet this requirement, as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.

(F) Fugitive emissions component identification when Method 21 is used to perform the monitoring survey or when OGI is used to perform the monitoring survey and the owner or operator chooses to comply with §60.5397a(d)(2) in lieu of §60.5397a (d)(1).

(G) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(H) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(I) Documentation of each fugitive emission, including the information specified in paragraphs (c)(15)(v)(I)(*1*) through (*3*) of this section.

(*1*) Location.

(*2*) Component ID and type of fugitive emissions component.

(*2*) Component ID.

(*3*) Instrument reading of each fugitive emissions component that requires repair when Method 21 is used for monitoring.

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

(K) For each component that cannot be repaired during the monitoring survey when the fugitive emissions were initially found:

(*1*) Number and type of components that were tagged or a digital photograph or video of each fugitive emissions component. The digital photograph or video must clearly identify the location of the component that must be repaired. Any digital photograph or video required under this paragraph can also be used to meet the requirements under paragraph (c)(15)(ii)(E) of this section, as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.

a digital photograph or video. The digital photograph or video must clearly identify the location of the component that must be repaired. Any digital photograph or video required under this paragraph can also be used to meet the requirements under paragraph (c)(15)(ii)(E) of this section, as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.

(*2*) The date and repair methods applied in each attempt to repair the fugitive emissions components.

(*3*) The date of successful repair of the fugitive emissions component.

(*4*) The date of each resurvey and instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(*5*) Identification of each fugitive emission component placed on delay of repair and explanation for each delay of repair.

(L) Records of calibrations for the instrument used during the monitoring survey.

(vi) Date of planned shutdowns that occur while there are any components that have been placed on delay of repair.

(vii) For the collection of fugitive emissions components at a compressor station, if a monitoring survey is waived under §60.5397a(g)(5), you must maintain records of the average calendar month temperature, including the source of the information, for each calendar month of the quarterly monitoring period for which the monitoring survey was waived.

(16) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(16)(i) through (v) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic pump constructed, modified or reconstructed.

(ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in §60.5393a, 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, manufacturer's specifications, and if the control device is designed

to achieve less than 95 percent emission reduction, a design evaluation or manufacturer's specifications indicating the percentage reduction achieved the control device is designed to achieve.

(iv) Records substantiating a claim according to §60.5393a(b)(5) that it is technically infeasible to capture and route emissions from a pneumatic pump to a control device or process; including the certification according to §60.5393a(b)(5)(ii) and the records of the engineering assessment of technical infeasibility performed according to §60.5393a(b)(5)(iii).

(v) You must retain copies of all certifications, engineering assessments and related records for a period of five years and make them available if directed by the implementing agency.

(17) For each closed vent system routing to a control device or process, the records of the assessment conducted according to §60.5411a(d):

(i) A copy of the assessment conducted according to §60.5411a(d)(1);

(ii) A copy of the certification according to §60.5411a(d)(1)(i); and

(iii) The owner or operator shall retain copies of all certifications, assessments and any related records for a period of five years, and make them available if directed by the delegated authority.

(18) A copy of each performance test submitted under paragraph (b)(9) of this section.

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

EFFECTIVE DATE NOTE: At 82 FR 25733, June 5, 2017, in §60.5420a, paragraphs (b)(7), (8), (12) and (c)(15) through (17) were stayed until Aug. 31, 2017.

§ 60.5421a What are my additional recordkeeping requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of §60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of §60.5401a(b)(1).

(1) When each leak is detected as specified in §60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in §60.5401a(b)(2), the information specified in paragraphs (b)(2)(i) through (x) of this section must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) "Above 500 ppm" if the maximum instrument reading measured by the methods specified in §60.5400a(d) after each repair attempt is 500 ppm or greater.

(v) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) must be signed by the owner or operator.

§ 60.5422a What are my additional reporting requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487a(a), (b)(1) through (3), (b)(5), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*https://www3.epa.gov/ttn/chief/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in §60.487a(b)(1) through (3) and (b)(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 (c)(2)(vii) through (viii):

(1) Number of pressure relief devices for which leaks were detected as required in §60.5401a(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in §60.5401a(b)(3).

§ 60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

(a) You must retain records of the calculations and measurements required in §60.5405a(a) and (b) and §60.5407a(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under §60.7(f) of the General Provisions.

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. The 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.

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of §60.5407a(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone

of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of §60.5407a(b)(3). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(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.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less than 2 LT/D of H2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(d) If you elect to comply with §60.5407a(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H2S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state. Electronic reporting to the EPA cannot be waived, and as such, the provisions of this

paragraph do not relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

§ 60.5425a What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

§ 60.5430a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Artificial lift equipment means mechanical pumps including, but not limited to, rod pumps and electric submersible pumps used to flowback fluids from a well.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(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 equations: $Y = 1.0 - 0.575 \log X$, where X is 2015 minus the year of construction, and $Y = 1.0$ when the year of construction is 2015; and

(iii) The applicable basic annual asset guideline repair allowance, B, is 4.5.

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities 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 Clean Air Act or the regulations promulgated thereunder are concerned; or

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

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.

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

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station for purposes of §60.5397a.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

Crude oil and natural gas source category means:

(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and

(2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.

Custody 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.

Custody transfer means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or

other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

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

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

First attempt at repair means, for the purposes of fugitive emissions components, an action taken for the purpose of stopping or reducing fugitive emissions of methane or VOC 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.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

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

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Hydraulic fracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in §60.485a(e) or §60.5401a(f)(2).

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

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

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

Intermittent/snap-action pneumatic controller means a pneumatic controller that is designed to vent non-continuously.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Liquid collection system means tankage and/or lines at a well site to contain liquids from one or more wells or to convey liquids to another site.

Local distribution company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

Low pressure well means a well that satisfies at least one of the following conditions:

(1) The static pressure at the wellhead following fracturing but prior to the onset of flowback is less than the flow line pressure;

(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 compressors, glycol dehydrators, heater/treaters, pneumatic pumps, pneumatic controllers, 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 daily throughput means the calculation of maximum daily throughput during the 30-day PTE evaluation period employing generally accepted methods.

Natural gas-driven diaphragm pump means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and

their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Permanent separator means a separator that handles flowback from a well or wells beginning when the flowback period begins and continuing to the startup of production.

Plug drill-out means the removal of a plug (or plugs) that was used to conducted hydraulic fracturing in different sections of the well.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Qualified Professional Engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere, or other mechanism that provides the same function.

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

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

Reduced emissions completion means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

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

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 of this subpart and is 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.

Returned to service means that a storage vessel affected facility that was removed from service has been:

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

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

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

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

Screenout means the first attempt to clear proppant from the wellbore through flowing the well to a fracture tank in order to achieve maximum velocity and carry the proppant out of the well.

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

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

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395a(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420a(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

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

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

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A-6 of this part.

Total SO_2 equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

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.

Underground storage vessel means a storage vessel stored below ground.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a well affected facility.

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

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the

fugitive emissions standards at §60.5397a, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries). 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 and (2) the flange upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

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.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

§60.5432a How do I determine whether a well is a low pressure well using the low pressure well equation?

(a) To determine that your well is a low pressure well subject to §60.5375a(f), you must determine whether the characteristics of the well are such that the well meets the definition of low pressure well in §60.5430a. To determine that the well meets the definition of low pressure well in §60.5430a, you must use the low pressure well equation below:

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

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Where:

(1) P_L is the pressure of flowback fluid immediately before it enters the flow line, expressed in pounds force per square inch (psia), and is to be calculated using the equation above;

(2) P_R is the pressure of the reservoir containing oil, gas, and water at the well site, expressed in psia;

(3) $L$is the true vertical depth of the well, expressed in feet (ft);

(4) q_o is the flow rate of oil in the well, expressed in cubic feet/second (cu ft/sec);

(5) q_g is the flow rate of gas in the well, expressed in cu ft/sec;

(6) q_w is the flow rate of water in the well, expressed in cu ft/sec;

(7) ρ_o is the density of oil in the well, expressed in pounds mass per cubic feet (lbm/cu ft).

(b) You must determine the four values in paragraphs (a)(4) through (7) of this section, using the calculations in paragraphs (b)(1) through (b)(15) of this section.

(1) Determine the value of the bottom hole pressure, P_{BH} (*psia*), based on available information at the well site, or by calculating it using the reservoir pressure, P_R (*psia*), in the following equation:

$$P_{BH}\ (psia) = \frac{1}{2} P_R$$

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(2) Determine the value of the bottom hole temperature, T_{BH} (F), based on available information at the well site, or by calculating it using the true vertical depth of the well, L *(ft)*, in the following equation:

$$T_{BH}\ (F) = (0.014 \times L) + 79.081$$

(3) Calculate the value of the applicable natural gas specific gravity that would result from a separator pressure of 100 psig, γ_{gs}, using the following equation with: Separator at standard conditions (pressure, p = 14.7 (*psia*), temperature, T = 60 (*F*)); the oil API gravity at the well site, γ_0; and the gas specific gravity at the separator under standard conditions, γ_{gp} = 0.75:

$$\gamma_{gs} = \gamma_{gp} \cdot \left(1.0 + 5.912\ x\ 10^{-5} \cdot \gamma_o \cdot T \cdot log\left(\frac{p}{114.7}\right)\right)$$

(4) Calculate the value of the applicable dissolved GOR, *Rs (scf/STBO)*, using the following equation with: The bottom hole pressure, P_{BH} (*psia*), determined in (b)(1) of this section; the bottom hole temperature, T_{BH} (*F*), determined in (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs}, calculated in (b)(3) of this section; the oil API gravity, γ_o, at the well site; and the constants, C1, C2, and C3, found in Table A:

$$R_s\left(\frac{scf}{STBO}\right) = C1 \cdot \gamma_{gs} \cdot P_{BH}{}^{C2} \cdot exp\left[C3\left(\frac{\gamma_o}{T_{BH} + 460}\right)\right]$$

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TABLE A—COEFFICIENTS FOR THE CORRELATION FOR R_S

Constant	$\gamma_{API} \leq$ **30**	γ_{API} **> 30**
C1	0.0362	0.0178
C2	1.0937	1.1870
C3	25.7240	23.931

(5) Calculate the value of the oil formation volume factor, *Bo (bbl/STBO)*, using the following equation with: the bottom hole temperature, T_{BH} (*F*), determined in paragraph (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs}, calculated in paragraph (b)(3) of this section; the dissolved GOR, Rs (scf/STBO), calculated in paragraph (b)(4) of this section; the oil API gravity, γo, at the well site; and the constants, C1, C2, and C3, found in Table B:

$$B_o\left(\frac{bbl}{STBO}\right) = 1.0 + C1 \cdot R_s + (T_{BH} - 60)\left(\frac{\gamma_o}{\gamma_{gs}}\right) \cdot (C2 + C3 \cdot R_s)$$

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TABLE B—COEFFICIENTS FOR THE CORRELATION FOR B_O

Constant	$\gamma_{API} \leq$ **30**	$\gamma_{API} >$ **30**
C1	4.677×10^{-4}	4.670×10^{-4}
C2	1.751×10^{-5}	1.100×10^{-5}
C3	-1.811×10^{-8}	1.337×10^{-9}

(6) Calculate the density of oil at the wellhead,

$$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right),$$

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using the following equation with the value of the oil API gravity, γo, at the well site:

$$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right) = \frac{141.5}{\gamma_o + 131.5} \times 62.4$$

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(7) Calculate the density of oil at bottom hole conditions,

$$\rho_{BH}\left(\frac{lbm}{cu\ ft}\right),$$

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using the following equation with: the dissolved GOR, Rs (scf/ STBO), calculated in paragraph (b)(4) of this section; the oil formation volume factor, Bo (bbl/ STBO), calculated in paragraph (b)(5) of this section; the oil density at the wellhead,

$$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right),$$

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calculated in paragraph (b)(6) of this section; and the dissolved gas gravity, $\gamma_{gd} = 0.77$:

$$\rho_{BH}\left(\frac{lbm}{cu\ ft}\right) = \frac{\rho_{WH} + 0.0136 \times Rs \times \gamma_{gd}}{Bo}$$

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(8) Calculate the density of oil in the well,

$$\rho_o\left(\frac{lbm}{cu\ ft}\right),$$

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using the following equation with the density of oil at the wellhead,

$$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right),$$

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calculated in paragraph (b)(6) of this section; and the density of oil at bottom hole conditions,

$$\rho_{BH}\left(\frac{lbm}{cu\ ft}\right),$$

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calculated in paragraph (b)(7) of this section:

$$\rho_o\left(\frac{lbm}{cu\ ft}\right) = 0.5 \times (\rho_{WH} + \rho_{BH})$$

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(9) Calculate the oil flow rate, q_o (*cu ft/sec,*) using the following equation with: the oil formation volume factor, *Bo* (bbl/ STBO), as calculated in paragraph (b)(5) of this section; and the estimated oil production rate at the well head, *Qo* (STBO/ day):

$$q_o\left(\frac{cu\ ft}{sec}\right) = \mathrm{Qo}\left(\frac{\mathrm{STBO}}{\mathrm{day}}\right) \times \mathrm{Bo}\left(\frac{\mathrm{bbl}}{\mathrm{STBO}}\right) \times 5.614\left(\frac{\mathrm{cu\ ft}}{\mathrm{bbl}}\right) \times \frac{1}{24 \times 60 \times 60}\left(\frac{day}{sec}\right)$$

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(10) Calculate the critical pressure, P_c (psia), and critical temperature, T_c (R), using the equations below with: Gas gravity at standard conditions (pressure, $P = 14.7$ (*psia*), temperature,

T = 60 (F)), $\gamma = 0.75$; and where the mole fractions of nitrogen, carbon dioxide and hydrogen sulfide in the gas are $X_{N2} = 0.168225$, $X_{CO2} = 0.013163$, and $X_{H2S} = 0.013680$, respectively:

$P_c(psia) = 678 - 50 \cdot (\gamma_g - 0.5) - 206.7 \cdot X_{N2} + 440 \cdot X_{CO2} + 606.7 \cdot X_{H2S}$

$T_c(R) = 326 + 315.7 \cdot (\gamma_g - 0.5) - 240 \cdot X_{N2} - 88.3 \cdot X\mathrm{CO}_2 + 133.3 \cdot X_{H2S}$

(11) Calculate reduced pressure, P_r, and reduced temperature, T_r, using the following equations with: the bottom hole pressure, P_{BH}, as determined in paragraph (b)(1) of this section; the bottom hole temperature, T_{BH} (F), as determined in paragraph (b)(2) of this section in the following equations:

$$P_r = \frac{P_{BH}}{P_c}$$

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$$T_r = \frac{T_{BH} + 460}{T_c}$$

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(12)(i) Calculate the gas compressibility factor, Z, using the following equation with the reduced pressure, P_r, calculated in paragraph (b)(11) of this section:

$$z = A + \frac{(1 - A)}{e^{B}} + C \cdot p_r^{D}$$

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(ii) The values for A, B, C, D in the above equation, are calculated using the following equations with the reduced pressure, P_r, and reduced temperature, T_r, calculated in paragraph (b)(11) of this section:

$$A = 1.39 \cdot (T_r - 0.92)^{0.5} - 0.36 * T_r - 0.101$$

$$B = (0.62 - 0.23 \cdot T_r) \cdot P_r + \left(\frac{0.066}{(T_r - 0.86)} - 0.037\right) \cdot P_r^2$$

$$+ \frac{0.32}{10^{9(T_r - 1)}} \cdot P_r^6$$

$$C = (0.132 - 0.32 \cdot \log(T_r))$$

$$D = 10^{0.3106 - 0.49 * T_r + 0.1824 * T_r^2}$$

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(13) Calculate the gas formation volume factor,

$$B_g \left(\frac{cuf/t}{scf}\right),$$

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using the bottom hole pressure, P_{BH} *(psia)*, as determined in paragraph (b)(1) of this section; and the bottom hole temperature, T_{BH} *(F)*, as determined in paragraph (b)(2) of this section:

$$B_g \left(\frac{cuf/t}{scf}\right) = 0.0283 \cdot \frac{Z \cdot (T_{BH} + 460)}{P_{BH}} ()$$

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(14) Calculate the gas flow rate,

$$q_g \left(\frac{cuf/t}{sec}\right),$$

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using the following equation with: the value of gas formation volume factor,

$$B_g \left(\frac{cuf/t}{scf}\right),$$

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calculated in paragraph (b)(13) of this section; the estimated gas production rate, Qg (scf/ day); the estimated oil production rate, Qo (STBO/ day); and the dissolved GOR, Rs (scf/ STBO), as calculated in paragraph (b)(4) of this section:

$$q_g \left(\frac{cf}{sec}\right) = (Q_g - R_s \cdot Q_o) \cdot B_g \cdot \frac{1}{24x60x60}$$

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(15) Calculate the flow rate of water in the well, q_w (*cu ft/sec*), using the following equation with the water production rate Qw (bbl/day) at the well site:

$$q_w\left(\frac{cf}{sec}\right) = Qw\left(\frac{bbl}{day}\right) \times 5.614\left(\frac{cf}{bbl}\right) \times \frac{1}{24 \times 60 \times 60}\left(\frac{day}{sec}\right)$$

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§§60.5433a-60.5499a [Reserved]

Table 1 to Subpart OOOOa of Part 60—Required Minimum Initial SO_2 Emission Reduction Efficiency (Z_i)

H_2S content of acid gas (Y), %	**Sulfur feed rate (X), LT/D**			
	2.0 < X < 5.0	**5.0 < X < 15.0**	**15.0 < X < 300.0**	**X > 300.0**
Y > 50	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller.		
20 < Y < 50	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller		97.9
10 < Y < 20	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 93.5, whichever is smaller	93.5	93.5
Y < 10	79.0	79.0	79.0	79.0

Table 2 to Subpart OOOOa of Part 60—Required Minimum SO_2 Emission Reduction Efficiency (Z_c)

	Sulfur feed rate (X), LT/D

H_2S content of acid gas (Y), %	**2.0 < X < 5.0**	**5.0 < X < 15.0**	**15.0 < X < 300.0**	**X > 300.0**
Y > 50	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller.		
20 < Y < 50	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 97.5, whichever is smaller		97.5
10 < Y < 20	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller	90.8	90.8
Y < 10	74.0	74.0	74.0	74.0

X = The sulfur feed rate from the sweetening unit (*i.e.*, the H_2S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H_2S (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide (SO_2) emission reduction efficiency, expressed as percent carried to one decimal place. Z_i refers to the reduction efficiency required at the initial performance test. Z_c refers to the reduction efficiency required on a continuous basis after compliance with Z_i has been demonstrated.

As stated in §60.5425a, you must comply with the following applicable General Provisions:

Table 3 to Subpart OOOOa of Part 60—Applicability of General Provisions to Subpart OOOOa

General provisions citation	**Subject of citation**	**Applies to subpart?**	**Explanation**

§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.5430a.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and record keeping	Yes	Except that §60.7 only applies as specified in §60.5420a(a).
§60.8	Performance tests	Yes	Performance testing is required for control devices used on storage vessels, centrifugal compressors, and pneumatic pumps, except that performance testing is not required for a control device used solely on pneumatic pump(s).
§60.9	Availability of information	Yes	

§60.10	State authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart OOOOa.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.
§60.14	Modification	Yes	To the extent any provision in §60.14 conflicts with specific provisions in subpart OOOOa, it is superseded by subpart OOOOa provisions.
§60.15	Reconstruction	Yes	Except that §60.15(d) does not apply to wells, pneumatic controllers, pneumatic pumps, centrifugal compressors, reciprocating compressors, storage vessels, or the collection of fugitive emissions components at a well site or the collection of fugitive emissions components at a compressor station.
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	

§60.18	General control device and work practice requirements	Yes	
§60.19	General notification and reporting requirement	Yes	

6560-50-P

40 CFR Part 60

[EPA-HQ-OAR-2017-0483; FRL-XXXX-XX-OAR]

RIN 2060-AT54

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed Rule.

SUMMARY: This action proposes reconsideration amendments to the new source performance standards (NSPS) at 40 Code of Federal Regulations (CFR) part 60, subpart OOOOa, (2016 NSPS OOOOa). The Environmental Protection Agency (EPA) received petitions for reconsideration on the 2016 NSPS OOOOa. The EPA granted reconsideration on three issues: (1) fugitive emissions requirements, (2) well site pneumatic pump standards, and (3) the requirements for certification of closed vent systems by a professional engineer based on specific objections to these requirements. This action proposes amendments and clarifications as a result of reconsideration of these issues. The proposed amendments also address other issues raised for reconsideration and make technical corrections and amendments to further clarify the rule.

DATES: *Comments.* Comments must be received on or before **[INSERT DATE 45 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**. Under the Paperwork Reduction Act (PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your

comments on or before **[INSERT DATE 45 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

Public Hearing. If a public hearing is requested by **[INSERT DATE 5 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**, then we will hold a public hearing on **[INSERT DATE 15 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]** at the location described in the **ADDRESSES** section. The last day to pre-register in advance to speak at the public hearing will be **[INSERT DATE 13 DAYS AFTER DATE OF PUBLICATION IN THE FEDERAL REGISTER]**.

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA-HQ-OAR-2017-0483, at *http://www.regulations.gov*. Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or removed from Regulations.gov. (See SUPPLEMENTARY INFORMATION for detail about how EPA treats submitted comments.) Regulations.gov is our preferred method of receiving comments. However, other submission methods are accepted:

- *Email:* a-and-r-docket@epa.gov. Include Docket ID No. EPA-HQ-OAR-2017-0483 in the subject line of the message.
- *Fax:* (202) 566-9744. Attention Docket ID No. EPA-HQ-OAR-2017-0483.
- *Mail:* To ship or send mail via the United States Postal Service, use the following address: U.S. Environmental Protection Agency, EPA Docket Center, Docket ID No. EPA-HQ-OAR-2017-0483, Mail Code 28221T, 1200 Pennsylvania Avenue, NW, Washington, DC 20460.
- *Hand/Courier Delivery:* Use the following Docket Center address if you are using express mail, commercial delivery, hand delivery, or courier: EPA Docket Center, EPA

WJC West Building, Room 3334, 1301 Constitution Avenue, NW, Washington, DC 20004. Delivery verification signatures will be available only during regular business hours.

Public Hearing. If a public hearing is requested, it will be held at {***INSERT LOCATION}. If a public hearing is requested, then we will provide details about the public hearing on our Web site at: *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/actions-and-notices-about-oil-and-natural-gas*. The EPA does not intend to publish another document in the Federal Register announcing any updates on the request for a public hearing. Please contact Aimee St. Clair at (919) 541-1063 or by email at stclair.aimee@epa.gov to request a public hearing, to register to speak at the public hearing, or to inquire as to whether a public hearing will be held. See **SUPPLEMENTARY INFORMATION** for instructions on registering and attending a public hearing.

FOR FURTHER INFORMATION CONTACT: For questions about this proposed action, contact Ms. Amy Hambrick, 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) 541-0964; fax number: (919) 541-3470; and email address: hambrick.amy@epa.gov. For information about the applicability of the new source performance standard (NSPS) to a particular entity, contact Ms. Marcia Mia, Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, EPA WJC South Building (Mail Code 2227A), 1200 Pennsylvania Avenue, NW, Washington DC 20460; telephone number: (202) 564–7042; and email address: mia.marcia@epa.gov.

SUPPLEMENTARY INFORMATION:

Public hearing. The EPA will make every effort to accommodate all speakers who arrive and register. If a hearing is held at a U.S. government facility, individuals planning to attend should be prepared to show a current, valid state- or federal-approved picture identification to the security staff to gain access to the meeting room. An expired form of identification will not be permitted. Please note that the Real ID Act, passed by Congress in 2005, established new requirements for entering federal facilities. If your driver's license is issued by a noncompliant state, you must present an additional form of identification to enter a federal facility. Acceptable alternative forms of identification include: Federal employee badge, passports, enhanced driver's licenses, and military identification cards. Additional information on the Real ID Act is available at https://www.dhs.gov/real-id-frequently-asked-questions. In addition, you will need to obtain a property pass for any personal belongings you bring with you. Upon leaving the building, you will be required to return this property pass to the security desk. No large signs will be allowed in the building, cameras may only be used outside of the building, and demonstrations will not be allowed on federal property for security reasons.

Docket. The EPA has established a docket for this rulemaking under Docket ID No. EPA-HQ-OAR-2017-0483. All documents in the docket are listed in the Regulations.gov index. Although listed in the index, some information is not publicly available, *e.g.*, CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically in Regulations.gov or in hard copy at the EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Avenue, NW, Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday

through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566-1744, and the telephone number for the EPA Docket Center is (202) 566-1742.

Instructions. Direct your comments to Docket ID No. EPA-HQ-OAR-2017-0483. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov*, including any personal information provided, unless the comment includes information claimed to be CBI or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or email. This type of information should be submitted by mail as discussed in the **ADDRESSES** section of this preamble.

The EPA may publish any comment received to its public docket. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.*, on the Web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit https://www2.epa.gov/dockets/commenting-epa-dockets.

The http://www.regulations.gov Web site is an "anonymous access" system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through http://www.regulations.gov, your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you

submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD-ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should not include special characters or any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at http://www.epa.gov/dockets.

Preamble Acronyms and Abbreviations. A number of acronyms and abbreviations 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
AVO	Auditory, Visual, and Olfactory
boe	Barrels of Oil Equivalent
BSER	Best System of Emissions Reduction
CAA	Clean Air Act
CBI	Confidential Business Information
CFR	Code of Federal Regulations
CO2 Eq.	Carbon dioxide equivalent
CVS	Closed Vent System
EPA	Environmental Protection Agency
FTE	Full Time Equivalent
GHG	Greenhouse Gases
GHGRP	Greenhouse Gas Reporting Program

LDAR	Leak Detection and Repair
NDE	No Detectable Emissions
NEMS	National Energy Modeling System
NSPS	New Source Performance Standards
NTTAA	National Technology Transfer and Advancement Act
OGI	Optical Gas Imaging
OMB	Office of Management and Budget
PE	Professional Engineer
PRA	Paperwork Reduction Act
PRV	Pressure Relief Valve
REC	Reduced Emissions Completion
RFA	Regulatory Flexibility Act
RIA	Regulatory Impact Analysis
TSD	Technical Support Document
UMRA	Unfunded Mandates Reform Act
VOC	Volatile Organic Compounds
VRU	Vapor Recovery Unit

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

I. General Information
A. Does this action apply to me?
B. What should I consider as I prepare my comments to the EPA?
C. How do I obtain a copy of this document and other related information?
II. Background
III. Legal Authority
IV. The Proposed Action
V. Discussion of Provisions Subject to Reconsideration

A. Pneumatic Pumps
B. Fugitive Emissions from Well Sites and Compressor Stations
C. Professional Engineer Certifications
D. Alternative Means of Emission Limitation (AMEL)
E. Other Reconsideration Issues Being Addressed
VI. Implementation Improvements
A. Reciprocating Compressors
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C. Definition of Certifying Official
D. Equipment in VOC service less than 300 hours/year
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F. Technical Corrections and Clarifications
VII. Impacts of This Proposed Rule
A. What are the air impacts?
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E. What are the forgone benefits of the proposed standards?
VIII. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
B. Executive Order 13771: Reducing Regulations and Controlling Regulatory Costs
C. Paperwork Reduction Act (PRA)
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E. Unfunded Mandates Reform Act (UMRA)
F. Executive Order 13132: Federalism
G. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments
H. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks
I. Executive Order 13211: Actions Concerning Regulations that Significantly Affect Energy Supply, Distribution, or Use
J. National Technology Transfer and Advancement Act (NTTAA)
K. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

I. General Information

A. Does this action apply to me?

Categories and entities potentially affected by this action include:

TABLE 1. 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. This table lists the types of entities that the EPA is now aware could potentially be affected by this action. Other types of entities not listed in the table could also be regulated. To determine whether your entity is regulated by this action, you should carefully examine the applicability criteria found in the final rule. If you have questions regarding the applicability of this action to a particular entity, consult the person listed in the **FOR FURTHER INFORMATION CONTACT** section, your air permitting authority, or your EPA Regional representative listed in 40 CFR 60.4 (General Provisions).

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

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

Do not submit information containing CBI to the EPA through *www.regulations.gov* or email. Send or deliver information identified as CBI only to the following address: OAQPS

Document Control Officer (C404-02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Docket ID Number EPA-HQ-OAR-2017-0483. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD-ROM that you mail to the EPA, mark the outside of the disk or CD-ROM as CBI and then identify electronically within the disk or CD-ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

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

In addition to being available in the docket, an electronic copy of the proposed action is available on the Internet. Following signature by the Administrator, the EPA will post a copy of this proposed action at *https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry*. Additional information is also available at the same Web site.

II. Background

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 OOOOa"). The 2016 NSPS OOOOa established NSPS for greenhouse gas and volatile organic compound (VOC) emissions from the oil and natural gas sector. For further information on the 2016 NSPS 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 OOOOa. Copies of

the petitions are provided in rulemaking docket EPA-HQ-OAR-2017-0483. A number of states and industry associations sought judicial review of the rule, and the litigation is currently being held in abeyance.

In a letter to petitioners dated April 18, 2017, the EPA granted reconsideration of the fugitive emissions requirements at well sites and compressor stations.[1] In a subsequent notice, the EPA granted reconsideration of two additional issues: well site pneumatic pump standards and the requirements for certification of closed vent systems (CVS) by a professional engineer.[2] This action proposes amendments and clarifications to address these issues, and grants reconsideration and proposes amendments to address several additional reconsideration issues, detailed in Section VI below. In addition, since the publication of the 2016 NSPS OOOOa, the EPA has received numerous questions relative to the implementation of the 2016 NSPS OOOOa requirements. This action also addresses these broad implementation issues that have been brought to the EPA's attention. The EPA believes that addressing these issues at the same time will provide clarity and certainty for the public and the regulated community with regard to these requirements.

III. Legal Authority

This action, which proposes certain amendments to the 2016 NSPS OOOOa, is based on the same legal authorities as those for the promulgation of that rule. The EPA promulgated the 2016 NSPS 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) requires the EPA to issue "standards of performance" for new sources in a category listed by the Administrator based on a finding that this category of

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[1] See Docket ID No. EPA-HQ-OAR-2010-0505-7730.
[2] 82 FR 25730.

stationary sources causes or contributes 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." This definition makes clear that the standard of performance must be based on controls that constitute "the best system of emission reduction. . . adequately demonstrated." The standard that the EPA develops, based on the best system of emission reduction (BSER), is commonly a numerical emissions 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 reflects the best technological system of continuous emission reduction, if it is not feasible to prescribe or enforce an emissions standard. This action includes proposed 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)(A). 81 FR 35829.

The proposed amendments in this notice result from the EPA's reconsideration of various aspects of the 2016 NSPS 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 Television 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).

IV. The Proposed Action

In this action, we are proposing amendments and clarifications on the following set of issues as a result of reconsideration: (1) pneumatic pump requirements; (2) fugitive emissions requirements at well sites and compressor stations; (3) professional engineering certification for CVS design and pneumatic pump technical infeasibility; and (4) alternative means of emissions limitations. In addition, we are proposing amendments to a number of other aspects of 2016 NSPS OOOOa, including well completion requirements and requirements at onshore natural gas processing plants. This action also addresses broad implementation issues that have been brought to the EPA's attention. Finally, we are proposing to correct technical errors that were inadvertently included in the final rule.

This document is limited to the specific issues identified in this notice. We will not respond to any comments addressing any other provisions of the 2016 NSPS OOOOa.

V. Discussion of Provisions Subject to Reconsideration

As summarized above, the EPA is proposing to address a number of issues that have been raised by different stakeholders through several administrative petitions for reconsideration of the 2016 NSPS OOOOa. The following sections present the issues raised by the petitioners that the EPA is addressing in this action and how the EPA proposes to resolve the issues.

A. Pneumatic Pumps

1. Definition of a Greenfield Site

The 2016 NSPS OOOOa includes a technical infeasibility provision from the well site pneumatic pump requirements for circumstances such as insufficient pressure or control device

capacity. 81 FR 35850. This provision was not provided for pneumatic pumps at greenfield sites (defined as a site, other than a natural gas processing plant, which is entirely new construction). *Id.* Petitioners stated that the term greenfield site was inadequately defined. For example, one petitioner questioned whether the term "new" as used in this definition is synonymous to how that term is defined in section 111 of the CAA. Additional questions included whether a greenfield remains forever a greenfield, considering that site designs may change by the time that a new control or pump is installed (which may be years later). Petitioners also objected to the EPA's assumption that the technical infeasibility encountered at existing well sites can be addressed when "new" sites are developed.

We previously concluded that circumstances, such as insufficient pressure or control device capacity, that could otherwise make control of a pneumatic pump technically infeasible at an existing location could be addressed in the site's design and construction. 81 FR 35850. However, petitioners have raised the concern that even at a greenfield site, there may be unique process or control design requirements that may not be compatible with controlling pneumatic pump emissions. Petitioners contend that such circumstances include the following:

- A new site design requires only a high-pressure flare to control emergency and maintenance blowdowns, and it is not feasible for a low pressure pneumatic pump discharge to be routed to such a flare; and
- A new site design requires only a small boiler or process heater, but such boiler or process heater could be insufficient to control pneumatic pumps emissions and routing pneumatic pump emissions to the boiler or process heater could result in safety trips and burner flame instability.

It is not clear that the scenarios described above present circumstances where it may be technically infeasible despite the site being newly designed and constructed; we therefore solicit comment on these examples, as well as other examples of technical infeasibility for a greenfield site. Regardless, while the EPA believes that most claims of technical infeasibility can be accounted for in the design and construction of a new site by selecting a control device or process that can control additional pneumatic pump emissions (*e.g.*, selecting a flare or slightly larger boiler that can accommodate such flows) with little additional cost, we cannot rule out the possibility that there could be infrequent cases of technical infeasibility at a greenfield site despite design and construction choices. We are therefore proposing to expand the technical infeasibility provision to all well sites by eliminating the distinction between greenfield sites and non-greenfield sites for the pneumatic pump requirements. The proposal would avoid the potential of requiring a greenfield from controlling the pneumatic pump emissions should it be technically infeasible to do so, while having no impact on the compliance obligations of other greenfield sites that do not have this issue. We solicit comment on this proposal. In addition, we solicit comment on site and control configurations that could present technical infeasible scenarios at a new construction site. We also solicit comment on information related to the additional costs that may be incurred if an owner or operator selects a control that can accommodate pneumatic pump emissions in addition to the control's primary purpose at a new construction site.

B. Fugitive Emissions from Well Sites and Compressor Stations

1. Monitoring Frequency

Monitoring Frequency for Well Sites. The 2016 NSPS OOOOa requires initial monitoring within 60 days of the startup of production and subsequent semiannual monitoring of the

collection of fugitive emissions components located at all well sites. We received petitions requesting changes to several aspects of fugitive monitoring frequencies: (1) a pathway to less frequent monitoring, (2) an exemption for low production well sites, and (3) an exemption for well sites located on the Alaskan North Slope. As discussed in detail in the following subsections, the EPA is proposing the following amendments to the fugitive emissions monitoring frequency for the collection of fugitive emissions components located at well sites:

- Semiannual monitoring for two years, followed by annual monitoring at well sites with average combined oil and natural gas production for the wells at the site being greater than or equal to 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production ("non-low production well sites");
- Annual monitoring for well sites with average combined oil and natural gas production for the wells at the site being less than 15 boe per day averaged over the first 30 days of production ("low production well sites");
- 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, and
- Annual monitoring and separate initial monitoring requirements for well sites and compressor stations located on the Alaskan North Slope.

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Pathway to Less Frequent Monitoring. Several petitioners requested that the EPA reconsider the frequency of monitoring to include a pathway to less frequent monitoring, specifically annual monitoring for well sites and semiannual monitoring for compressor stations.[3] In the 2015 NSPS OOOOa proposal, the EPA proposed alternative monitoring frequencies that would adjust up and down in frequency based on the percentage of fugitive emissions

[3] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682, EPA-HQ-OAR-2010-0505-7685 and EPA-HQ-OAR-2010-0505-7686.

components identified with fugitive emissions during monitoring events. For instance, if the first two semiannual monitoring surveys resulted in less than one percent of the collection of fugitive emissions components with fugitive emissions, then the well site could have moved to annual monitoring. For well sites with more than three percent of the fugitive emissions components identified with fugitive emissions, quarterly monitoring would have been required. However, as noted in the preamble to the 2016 NSPS OOOOa,[4] the commenters opposed this approach and raised specific concerns that performance-based monitoring frequencies would be costly, time-consuming, and impose a complex administrative burden for the industry and states. Noting the additional administrative burden and the potential issues with operating permits, we concluded in that rulemaking that "the potential for a performance-based approach to encourage greater compliance is outweighed in this case by the additional burdens and the complexity it would add."[5] Therefore, the monitoring frequencies established in the 2016 NSPS OOOOa were fixed at semiannual for well sites and quarterly for compressor stations based on the BSER analysis.

One petitioner asserts that the EPA's cost-effectiveness analysis is not accurate and should be revised.[6] In support, the petitioner provided data (which is described in more detail below). The petitioner suggested that, at a minimum, the EPA should require semiannual monitoring at well sites for an initial period of 2 years followed by less frequent monitoring frequencies such as annual monitoring for sites that do not have a significant number of "leaking"[7] components.[8] In addition, the petitioners suggested there should be a pathway out of monitoring when production declines such that the well site would be considered a low

[4] See 81 FR 35857.
[5] See 81 FR 35857.
[6] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.
[7] While the petitioner used the term leaking, the EPA is clarifying they were referring to fugitive emissions, and not equipment leaks such as those subject to a leak detection and repair (LDAR) program at onshore natural gas processing plants.
[8] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.

production well site. Low production well sites are discussed in a separate subsection of this preamble, and as discussed in that subsection, we are proposing annual monitoring for low production well sites. While we are not providing a pathway out of monitoring because of production levels, as discussed in this subsection, we are proposing a pathway out of monitoring once the major production and processing equipment is removed from the well site.

As mentioned above, the petitioner provided information in order to demonstrate lower percentages of fugitive emissions than used in the EPA's analysis. However, this information was limited to Colorado and the Barnett Shale region of Texas, and may not represent the percent of fugitive emissions realized in other areas with heavy oil and natural gas production activities.[9] This information included the number of components with fugitive emissions by component type, an estimate of the total number of each component type, and an estimated percentage of fugitive emissions components identified with fugitive emissions using both OGI and Method 21 of Appendix A-7 to Part 60 ("Method 21"). Subsequent to the submission of their petition, this petitioner also provided additional data on the initial fugitive emissions percentages for well sites located in 14 states.[10] While the letter from the petitioner stated that on average 0.4 percent of fugitive emissions components were identified with fugitive emissions, this percentage was based on the aggregation of fugitive emissions by dividing the total number of fugitive emissions components identified with fugitive emissions by the total estimated number of fugitive emissions components monitored, and thus did not address the average percentage of fugitive emissions components found with fugitive emissions at individual well sites. Accordingly, as presented by the petitioner, the data could not be directly transferred to our

[9] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.
[10] Alaska, Arkansas, Colorado, Louisiana, Montana, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, Utah, West Virginia, and Wyoming.

model plant. Instead, the EPA has evaluated the data provided to determine the average percentage of fugitive emissions components identified with fugitive emissions at the individual well site level, consistent with our treatment of well site fugitive emissions. For the individual well sites, this percentage ranged from 0 percent to 13.47 percent. This results in an average percentage of 0.54 percent or an average of 2 components per well site per survey with fugitive emissions.[11] This contrasts with the EPA's estimate of 4 components per well site per survey with fugitive emissions, or 1.18 percent, used in the 2016 NSPS OOOOa. Additional information on our evaluation of this data is included in the memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API*, located at Docket ID No. EPA-HQ-OAR-2017-0483. While we have not incorporated any changes to the model plants as a result of these data from the petitioner, we did evaluate each of the options using both average percentages (0.54 and 1.18 percent), as discussed further in this section, and reached the same conclusions. We are soliciting comment on these data relevant to the determination of the average percentage of fugitive emissions components identified with fugitive emissions and our evaluation of the data. Additionally, we are soliciting additional information that would suggest a different percentage should be considered, including counts of the components monitored, the number of identified fugitive emissions, the type of fugitive emissions components monitored, the type of fugitive emissions components found with fugitive emissions, the production levels of the wells located at the well site, age of the wells at the well site, location of the well site, and how the surveys were performed, including the monitoring instrument used and the regulatory program followed. As discussed further below, we are particularly interested in how these variables differ over time and comparisons of facilities implementing fugitive emissions programs and those that have not.

[11] See memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 17, 2018.

In addition to the percentage of fugitive emissions components identified with fugitive emissions, the EPA has evaluated other available information and updated the well site model plants. We updated the model plants used in support of the 2016 NSPS OOOOa based on updates in the Greenhouse Gas Inventory (GHGI) program for major equipment counts at well sites. Specifically, the number of meters/piping decreased from 3 to 2 for the gas well site and oil with associated gas well site model plants. No changes were made to the oil well site model plant as a result of updates in the GHGI.

In addition to updates made based on updates to the GHGI, we also added one controlled storage vessel per model plant and an emissions factor for pressure relief devices (PRDs), such as thief hatches and pressure relief valves (PRVs) from these controlled storage vessels because controlled storage vessels that are not affected facilities subject to the requirements in 40 CFR 60.5395a are considered fugitive emissions components. In evaluating the quantity of fugitive emissions from storage vessels, we considered data indicating that the frequency of fugitive emissions from controlled storage vessels may be much higher than that for other fugitive emissions components. For purposes of the model plant, we are adding one controlled storage vessel with one PRD. We are aware that owners and operators may be claiming that many of their controlled storage vessels are subject to the fugitive emissions programs rather than affected facilities subject to the requirements in 40 CFR 60.5395a for storage vessels with the potential to emit greater than 6 tpy of VOC (suggesting that we should be adding more than one controlled storage vessel to the model plant).[12] However, as discussed further in section V.B., many of these claims of exclusion may be improper, meaning that the number of controlled storage vessels under the fugitive emissions program may be overstated. Accordingly, even our

[12] See the TSD for additional information on the fugitive emissions from storage vessels.

estimate of one controlled storage vessel per well site that may be subject to the fugitive emissions program may be an overestimate. We are soliciting comment on our assumption of one controlled storage vessel per well site subject to fugitive emissions requirements and data to further refine the model plant with regards to controlled storage vessel fugitive emissions. The emissions factor used for PRDs on controlled storage vessels was derived from a study that conducted aerial surveys for emissions at oil and gas production sites located in seven basins across the United States.[13] We did not update the average emissions factors for other fugitive emissions components based on information in this study because the study stated that emissions from individual components, such as valves, could not be identified during the surveys. In this study, helicopter-based OGI monitoring was performed at 8,220 well sites. A total of 494 fugitive emission sources were identified at 327 sites, averaging approximately 1.5 fugitive sources per site. Fugitive emissions[14] from storage vessels accounted for 92 percent of the total fugitive sources, with 198 fugitive sources associated with storage vessel PRVs and 257 fugitive sources associated with thief hatches, though it was unclear from the study if all of these storage vessels were equipped with a CVS that routes emissions to a control device. The estimated detection limit for the OGI instrument observed by this study was 1 gram per second (g/s) for heavier hydrocarbons and 3 g/s for methane.[15] Based on this information, we used the 1 g/s estimated emission rate in combination with the frequency of storage vessel emissions identified in the study to estimate emissions from thief hatches for purposes of the model plants. However, we acknowledge that the emissions are likely underestimated when using this information

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[13] Lyon, David R., et al., *Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites*. Environmental Science and Technology 2016, 50, 4877-4886.

[14] It was difficult for the Lyon, David R., et al., study to attribute emissions from storage vessels to specific malfunctions or normal operations. The study predicted liquid unloading events and stuck open separator dump valves would contribute less than 0.1% of the emissions detected for each event. The other 99.8% of the storage vessel emissions were not characterized by the study. See *Id.* at pages 4882-4883.

[15] *Id.*

because small or medium sized emissions would not be visible during an aerial OGI survey. Additional information about the model plants and analysis is included in the Background Technical Support Document (TSD) located at Docket ID No. EPA-HQ-OAR-2017-0483.

Emissions for the other fugitive emissions components were estimated using average emissions factors for oil and gas production operations, found in Table 2-4 of the *Protocol for Equipment Leak Emission Estimates* (1995 Protocol).[16] These average emissions factors are used when screening data are not available, as is the case when OGI is used as the monitoring instrument,[17] and provide an average emission rate for the collection of fugitive emissions components at the site. For example, the average emissions factors can be used to estimate emissions from the collection of all valves at the site, instead of needing to estimate emissions from each individual valve and averaging the emissions across the collection of valves. In addition to the information regarding the percentage of fugitive emissions components identified with fugitive emissions, the petitioner also presented updated emissions factors for these fugitive emissions components.[18] The petitioner attempted to create new average emissions factors by using the newly presented 0.4 percent for identified fugitive emissions and scaling the average emissions factors documented in the 1995 Protocol. We do not agree with the approach of scaling emissions factors presented by the petitioner for the non-storage vessel PRD fugitive emissions components and have not evaluated the cost of control using these scaled factors. Additional information on our evaluation of the scaled emissions factors is included in the memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API*,

[16] U.S. Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates. Table 2-4. November 1995 (EPA-453/R-95-017).
[17] OGI instruments that are currently widely available provide a qualitative indication of emissions and do not provide an indication of the concentration levels of fugitive emissions. However, we recognize that quantitative OGI is a new technological development that may allow estimations of mass emission rates in the future.
[18] See memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 17, 2018.

located at Docket ID No. EPA-HQ-OAR-2017-0483. Therefore, we continue to use the average emissions factors in the 1995 Protocol to calculate emissions in the model plants for the fugitive emissions components, excluding controlled storage vessel PRDs.

Since we continue to utilize the average emissions factors, the emissions were not affected by the percentage of fugitive emissions components identified with fugitive emissions. When estimating the costs of the fugitive emissions program at well sites, the only place we account for this percentage is related to the cost of repairs. As noted previously, there is a difference of two components identified with fugitive emissions per well site when using the petitioner's reported average of 0.54 percent and our estimate of 1.18 percent. The difference in repair costs for the proposed monitoring frequency discussed below is $70. We have evaluated the cost of control using both the 0.54 and 1.18 percent values and reached the same conclusions regarding which option is reasonable, therefore we have maintained the 1.18 percent as the estimated percentage of fugitive emissions components identified with fugitive emissions in this proposal. Additional information about this analysis is available in the TSD.

After updating the model plants, the EPA performed a sensitivity analysis to understand how the monitoring frequencies would affect emission reductions and costs. We examined the costs and emission reductions for the non-low production model plant at semiannual, annual, and stepped (semiannual for 2 years to annual) monitoring frequencies. We applied the two approaches used in the 2016 NSPS OOOOa (single and multipollutant approaches)[19] for

[19] See 81 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 equally controlled, therefore half of the cost is apportioned to the methane emission reductions and half of the cost if apportioned to the VOC emission reductions. In this evaluation, we examined both approaches across the range of identified monitoring frequencies: semiannual, annual, and semiannual for 2 years followed by annual.

evaluating cost-effectiveness of these various monitoring frequencies applied to the fugitive emissions program for reducing both methane and VOC emissions from non-low production well sites.

As shown in the TSD, for semiannual monitoring of non-low production well sites, under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,164 per ton of methane reduced, and $965 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,186 per ton of VOC reduced, and $3,473 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $2,093 per ton VOC reduced, and $1,736 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $582 per ton methane reduced, and $483 per ton if natural gas savings are considered.[20]

Commented [A2]: EPA edit: Costs are updated to reflect corrections in corresponding spreadsheets.

While the cost of control for semiannual monitoring appears to be reasonable, we recognize several limitations with our estimates of the emission reductions and implementation costs, which likely result in a significant overstatement of the cost-effectiveness of control on an ongoing basis. First, the cost of control presented here and in the TSD are based on the implementation of a fugitive emissions program where monitoring has not previously occurred. The baseline emissions represented in the non-low production model plants are based on uncontrolled fugitive emissions, that is, emissions that would go unmitigated without a monitoring and repair program. Further, each monitoring frequency has a corresponding emission reduction based on expected control efficiencies of the OGI-based monitoring program

[20] See the TSD for full comparison of cost.

at the various monitoring frequencies. Thus, in our cost-effectiveness analysis the emission reductions are assumed to be constant over the life of the fugitive emissions program at each individual well site.

Additionally, the model plants assume that the percentage of components found with fugitive emissions remains the same throughout the life of the fugitive emissions program. This assumption that the percentage do not change over time is in contrast with how we have evaluated similar programs aimed at fugitive emissions. When we have evaluated the implementation of a new leak detection and repair (LDAR) program where monitoring was not previously required in other actions, we have recognized that initial percentages of leaks are generally higher than subsequent leak percentages for the non-storage vessel PRD fugitive emissions components.[21] As an LDAR program is implemented, leak percentages decline until they reach a "steady state". As illustrated in Figure 5-35 of the *Protocol for Equipment Leak Emission Estimates*,[22] the highest leak percentage is identified during the first monitoring event. The leak percentage then declines over time and reaches a point of steady state where the leak percentage is lower than that identified in the first monitoring event. Additional discussion of the leak percentages, including a discussion of the information evaluated related to leak percentages, is included in the TSD.

In this action, the EPA seeks to incorporate this understanding, that initial percentages of fugitive emissions components identified with fugitive emissions are higher than subsequent percentages in a newly implemented fugitive emissions program. We know that, by assuming constant emission reductions every year (without taking into account the reduced percentages as

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[21] See *Final Impacts Analysis for Regulatory Options for Equipment Leaks of VOC in the SOCMI*, located at Docket ID. EPA-HQ-OAR-2006-0699-0090 at p. 8.
[22] U.S. Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates. Section 5.3 and Figure 5-35. November 1995 (EPA-453/R-95-017).

the program is implemented), we have overestimated the emission reductions and therefore the cost-effectiveness of the various monitoring frequencies as the program continues. Therefore, while semiannual monitoring is cost effective when it is first implemented, as reflected in our cost analysis described above, we do not have information to conclude that semiannual monitoring remains cost-effective as the percentage of fugitive emissions declines and approaches a "steady state." While we do not have enough information to determine how long it takes for this percentage to reach a "steady state," we recognize that certain existing LDAR requirements, such as those for natural gas processing plants in 40 CFR 60.5400a(b), allow for less frequent monitoring, such as annual monitoring, after a period of 5 consecutive quarters. This suggests that steady state may be reached at around 2 years of implementation of a monitoring and repair program. Therefore, we are proposing that well sites will reach this steady state within 2 years. In light of the above, we propose to change the current monitoring frequency for non-low production well sites from a permanent semiannual monitoring frequency to semiannual monitoring for an initial 2-year period and annual monitoring frequency thereafter. We solicit comment and data to help us better understand what this "steady state" percentage may be for fugitive emissions components from semiannual monitoring, how long it takes for the program to reach such a state after monitoring begins, and any other relevant information that would help either confirm or eliminate our concern regarding the long-term cost-effectiveness of semiannual monitoring.

There are several well sites that incorporated fugitive monitoring programs prior to the 2016 NSPS OOOOa for various purposes, including compliance with state or local requirements. We are soliciting data regarding the percentage of fugitive emissions components identified with fugitive emissions at these well sites for each survey performed to understand how this

percentage may change over time; the data should include information on when the well site began producing, the start date of the fugitive program at the well site, the frequency of monitoring, an indication of the location of the well site *(e.g.,* basin name or state), and how the surveys are performed, including the monitoring instrument used and the regulatory program followed. We are also soliciting comment and supporting data related to annual monitoring, without the step down, for well sites.

The EPA is soliciting information that can be used to evaluate if additional changes are necessary to the model plants. Specifically, the EPA requests information that has been collected from implementing fugitive monitoring programs, including information on leak concentrations where Method 21 has been used for monitoring. This information could also demonstrate the actual equipment counts or fugitive emissions component counts at the well site, in relation to the number of fugitive emissions identified during each monitoring survey. Additionally, the EPA is soliciting information that can be used to further refine the emission reductions achieved with OGI-based monitoring at the various monitoring frequencies. As discussed in the TSD, the EPA estimates 40 percent emission reduction for annual monitoring, 45 percent for the stepped monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring. While these emission reductions were based on the best available information, the EPA is aware there may be studies that may provide additional analysis on the effectiveness of OGI monitoring that can further refine our estimates. Specifically, the EPA is requesting information on any analyses performed on the effectiveness of OGI monitoring at different monitoring frequencies and the data underlying these analyses, including information on how the data was gathered, what the date represents, and how the analysis was performed.

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Further, we are proposing that fugitive monitoring may stop when an owner or operator removes all major production and processing equipment from the well site, such that it contains only one or more wellheads. The 2016 NSPS OOOOa excludes well sites that contain only one or more wellheads from the fugitive emissions requirements because fugitive emissions at such well sites are extremely low. 80 FR 56611. In the preamble to the 2015 NSPS OOOOa proposal, we noted that wellhead only well sites do not have ancillary equipment (such as storage vessels, closed vent systems, control devices, compressors, separators, and pneumatic controllers), thus resulting in low emissions. For the same reason, we anticipate that, when a well site becomes a wellhead only well site due to the removal of all ancillary equipment, its fugitive emissions would also be extremely low because the number of fugitive emissions components is low. This proposal uses the term "major production and processing equipment" to refer to ancillary equipment without which the fugitive emissions would be extremely low. We are, therefore, proposing to define "major production and processing equipment" as including separators, heater treaters, storage vessels, glycol dehydrators, pneumatic pumps, or pneumatic controllers. We have also evaluated the cost-effectiveness of monitoring a wellhead only well site and find it not to be cost-effective. For that analysis, we developed a model plant that contains only 2 wellheads and no major production and processing equipment. For the annual monitoring frequency, we found the cost for control was greater than $5,000 per ton of methane reduced and greater than $20,000 per ton of VOC reduced.[23] Additional discussion about this model plant and the cost of control is included in the TSD. In light of the above, we are proposing that monitoring may discontinue when all major production and processing equipment at a well site has been

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[23] We did not perform an analysis for the cost of control at a semiannual monitoring frequency for these wellhead only well sites because we determined that annual monitoring was not cost-effective. Therefore, at more frequent monitoring, it would also not be cost-effective because there are higher costs compared to annual monitoring.

removed, resulting in a wellhead only well site. We are soliciting comment on the proposed exemption and definition of major production and processing equipment for purposes of this specific proposal, including whether additional equipment should be included in this list, such as compressors and engines.

As explained above, we are proposing that monitoring is no longer required when all major production and processing equipment at a well site has been removed, resulting in a wellhead only well site. We note that if the production from this well site (with all major production and processing equipment removed), is sent to a separate tank battery for processing, that separate tank battery (which itself is a well site as defined in 40 CFR 60.5430a) is considered modified and subject to the fugitive emissions requirements. Additional discussion on this topic is included in section V.B.2 of this preamble. We further note that the proposed monitoring exemption would not change the affected facility status of the collection of fugitive emissions components located at a well site that removes equipment to become a wellhead only well site; it would remain an affected facility. We are proposing to require that owners or operators report the following information in the next annual report following the change to a wellhead only well site: (1) a statement that the well site has removed all major production and processing equipment, (2) the final date that equipment was removed, (*i.e.,* the date that the well site began meeting the definition of a wellhead only well site), and (3) the location receiving the production from the well site. Provided the well site remains a wellhead only well site, no additional reporting related to fugitive emissions would be required. If in the future production equipment is reintroduced to the well site, the fugitive emissions requirements would restart with initial monitoring followed by the subsequent monitoring, the frequency of which would be based on the subcategory (non-low production or low production) that the well site was classified

as when it first became an affected facility for fugitive emissions requirements (e.g. not the subcategory that the well site is classified when production equipment is reintroduced). We are soliciting comment on this proposed exemption from monitoring for well sites that become wellhead only sites, including the proposed reporting requirements and subsequent monitoring requirements should the wellhead only status of the well site later change.

Low Production Well Sites. The 2016 NSPS OOOOa requires semiannual monitoring for all well sites, regardless of the production levels for the well site. In 2015, the EPA proposed to exclude low production well sites (*i.e.,* well sites where the average combined oil and natural gas production is less than 15 boe per day averaged over the first 30 days of production) from fugitive emissions requirements. 80 FR 56639. It was our understanding in 2015 that fugitive emissions were low at low production well sites and that these well sites were mostly owned and operated by small businesses. We were concerned about the burden on small businesses, especially with relatively low emission reduction potential. *Id.* However, in the preamble to the 2016 NSPS OOOOa, the EPA stated that we "believe that low production well sites have the same type of equipment (*e.g.,* separators, storage vessels) and components (*e.g.,* valves, flanges) as well sites with production greater than 15 boe per day. Because we did not receive additional data on equipment or component counts for low production wells, we believe that a low production well model plant would have the same equipment and component counts as a non-low production well site." 81 FR 35856. We based this conclusion on the fact that we had no data to indicate that the number and types of equipment were different at low production well sites than at non-low production well sites. Additionally, comments received on the 2015 proposal indicated that small businesses would not benefit from the proposed exemption because

these types of wells would not be economical to operate and few operators, if any, would operate new low production well sites. *Id.*

In a letter dated April 18, 2017, the Administrator granted reconsideration of several aspects of the 2016 NSPS OOOOa, including applying the fugitive emissions requirements at 40 CFR 60.5397a to low production well sites.[24] The petitioner who raised this issue for reconsideration identified in its petition what they classified as an inconsistency between the EPA's justification for not exempting low production well sites from the fugitive emissions requirements and the EPA's rationale for the definition of modification for purposes of those same requirements.[25] This petitioner observed that it appeared the EPA relied on data indicating the same equipment counts were present at all well sites regardless of production levels to justify regulating fugitive emissions at low production well sites, while defining modification by events that increase production (*i.e.*, drilling a new well, hydraulic fracturing a well, or hydraulic refracturing a well), which the EPA concludes will increase emissions whether or not there is change in component counts. The petitioner then stated that:

> "EPA's rationale, that fugitive emissions are a function of the number and types of equipment, and not operating parameters such as pressure and volume, is inconsistent with EPA's justification for what constitutes a "modification" for an existing well site. EPA assumes that fracturing or refracturing an existing well will increase emissions because of the additional production, *i.e.*, the additional pressure and volume. EPA cannot ignore the laws of physics to the detriment of low production wells in one instance and then "honor" them in another context to eliminate an "emissions increase" requirement in the traditional definition of "modification."[26]

As we explain in detail in section V.B.2 related to modifications, operating pressures and volumes are one set of factors that can cause changes in the fugitive emissions at a well site.

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[24] See Docket ID No. EPA-HQ-OAR-2010-0505-7730.
[25] See Docket ID No. EPA-HQ-OAR-2010-0505-7685.
[26] See Docket ID No. EPA-HQ-OAR-2010-0505-7685, p. 5.

However, as described below, we also agree with other petitioners that equipment counts can vary based on the amount of production at a well site.[27]

The petitioners noted that as production increases it is possible that additional major production and processing equipment is added to the well site to handle this increase. The opposite impact was also presented by petitioners, in that as production declines, major production and processing equipment is either disconnected or removed from the well site so it can be used somewhere else.[28] Additionally, the petitioners noted that operating pressures for the well site are generally affected by production, and depleted wells may not be able to provide enough pressure to meet the pressure requirements of the gas gathering system.[29] In comments submitted on the November 2017 Notice of Data Availability ("2017 NODA"), one commenter noted that the information used as the basis for the EPA's decision to treat low production well sites the same as non-low production well sites was based on a flawed analysis of the data.[30] This commenter noted that emissions were presented in such a way as to compare the total well site emissions as a percentage of production. As noted by the commenter, this type of analysis unfairly makes it appear that low production well sites are "super-emitters" because when emissions are compared based on a percentage of production, even small emissions can appear to be upwards of 50 percent or more of the total production for the well site. Further, one petitioner reiterated concerns about the impacts of fugitive emissions requirements on small businesses, including stating that the "marginal profitability will mean that many wells will be shut in instead of making the investment to conduct LDAR surveys."[31] While we currently do not have

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[27] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.
[28] See Docket ID No. EPA-HQ-OAR-2010-0505-7682, p. 12.
[29] *Id.*
[30] See Docket ID No. EPA-HQ-OAR-2010-0505-12454.
[31] See Docket ID No. EPA-HQ-OAR-2010-0505-7685.

information supporting this assertion, we solicit information confirming or refuting this concern including analyses on the number of wells that may be shut in as a result of requiring fugitive emissions monitoring and how these concerns may vary based on production level (presumably wells with higher production would be better able to adsorb more frequent monitoring). At a minimum, any information provided should include the costs of implementing the fugitive emissions requirements compared to the profitability of the well site over the life of the well site from first production through shut in. Further, any information provided should include information as to the length of the life of the well site, beginning at first production, and by how much that total duration would be shortened by the shut in, as well as information as to total production over the life of the well site, beginning at first production, and the amount of production that would be reduced by the shut in. If information received supports the allegation that fugitive emissions monitoring would lead to a significant number of shut-ins at a significantly earlier point in the life of the well site and with a significant loss of overall production volume, that would further support our proposals regarding monitoring frequency. However, assertions presented without supporting information will not be deemed helpful related to this discussion.

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In light of the comments, the petitions, and data made available after promulgation of the 2016 NSPS OOOOa, the EPA has re-examined whether fugitive emissions are different for low production well sites. Following promulgation of the 2016 NSPS OOOOa, the EPA received information from one stakeholder which contained component level emissions information for well sites in the Dallas/Fort Worth area (herein referred to as the "Fort Worth Study").[32] The EPA evaluated the emissions calculation workbook included in Appendix 3-B of the Fort Worth

[32] "The Natural Gas Air Quality Study (Final Report)", prepared by Eastern Research Group, Inc. July 13, 2011, available at *http://fortworthtexas.gov/gaswells/air-quality-study/final/*.

Study and was able to identify 27 well sites with throughput less than 90 thousand cubic feet per day (Mcfd), or 15 boe per day. While this throughput was the throughput reported for the prior day and not the average over the first 30 days as we are defining low production well sites in this proposed reconsideration, this information was relevant to understanding both component counts and emissions for the well sites in the study as compared to production values. As explained in the memorandum *Analysis of Low Production Well Site Fugitive Emissions from the Fort Worth Air Quality Study* ("Fort Worth Study Memo"), located at Docket ID No. EPA-HQ-OAR-2017-0483, the EPA was able to directly compare fugitive component emissions from these 27 low production well sites to the fugitive component emissions from the other approximately 300 well sites in the study. This evaluation demonstrated that average emissions across the low production well sites were lower than those at the non-low production well sites in the study. Additionally, the average equipment counts were also lower for the low production well sites than those at non-low production well sites in the study. When fugitive emissions were considered from non-tank and non-controller fugitive sources, the average methane emissions were approximately 2.5 tpy for low production well sites, and 24 tpy for non-low production well sites. When storage vessel fugitives (*e.g.*, thief hatches) were considered, average methane emissions were 13 tpy for low production well sites and 33 tpy for non-low production well sites.[33]

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Given this information, the EPA evaluated fugitive emissions from well sites by subcategorizing well sites based on production: (1) non-low production and (2) low production. Within each of these subcategories, the EPA modified the three model plants used in the 2016 NSPS OOOOa: gas well site, oil well site (defined as GOR <300), and oil with associated gas

[33] See the memorandum *Analysis of Low Production Well Site Fugitive Emissions from the Fort Worth Air Quality Study*, located at Docket ID No. EPA-HQ-OAR-2017-0483.

well site (defined as GOR ≥300). A discussion of the non-low production well site model plants is included in the previous discussion on the pathway to less frequent monitoring.

The EPA created new model plants using the component count information obtained for the low production well sites in the Fort Worth Study in order to compare the emissions using the emissions factors used by the EPA for model plant calculations to the measured emissions from the study. For the low production gas well site model plant, we used the average equipment counts for the low production well sites in the Fort Worth Study. We then compared the corresponding average component counts (*e.g.,* valves, connectors) for this equipment in the low production gas well site to the non-low production gas well site to determine a scaling factor. This scaling factor was applied to the non-low production component counts for the oil well site and oil with associated gas well site model plants in order to evaluate these types of well sites for the low production subcategory. Additional information about the low production well site model plants and analysis is included in the TSD.

As mentioned previously, in the 2016 NSPS OOOOa the EPA did not expect production levels to affect the amount of major production and processing equipment at well sites. However, as discussed above, we have since evaluated data showing that low production wells have fewer equipment, and therefore fewer fugitive emissions components. Therefore, in this proposal, we have incorporated the new data and developed model plants for low production well sites. The estimated emissions and cost-effectiveness are different between the low production and non-low production well site model plants. For example, the estimated baseline methane emissions are 5.91 and 4.80 tpy for non-low production and low production gas well site model plants, respectively. We performed additional analysis on the emissions data presented in the Fort Worth Study to determine if there was a statistical difference between the low production and non-low

production methane emissions. This analysis determined the mean methane emissions were 157 and 116 tpy for non-low production and low production well sites, respectively. Additional information on this analysis is included in the Fort Worth Study Memo located at Docket ID No. EPA-HQ-OAR-2017-0483.

In addition to the Fort Worth Study, the EPA evaluated other available information for comparing low and non-low production well sites. While we did not find the same level of detail regarding component counts to allow us to further refine the low production well site model plants, several of the studies indicated that there is a general correlation between production and fugitive emissions, where fugitive emissions increase as production increases at the well site. Further, some studies indicated that while the number of fugitive emissions components was lower for low production well sites, a few outliers were identified suggesting that all well sites have the potential for fugitive emissions greater than the estimates in the model plants. Finally, the studies also indicated that storage vessel thief hatches were a large source of fugitive emissions when compared to other fugitive emissions components, such as valves and connectors. Additional information about these studies is presented in the memorandum *Low Production Well Site Fugitive Emissions* ("Low Production Memo"), located at Docket ID No. EPA-HQ-OAR-2017-0483.

We examined the costs and emission reductions for the low production model plant at semiannual, annual, and stepped monitoring frequencies using the single and multipollutant approaches discussed previously for non-low production well sites. The calculation of the costs, emission reductions, and cost of control for each option are explained in detail in the TSD. Additionally, as shown in the TSD, while the costs for repairing components that are found to have fugitive emissions during a fugitive monitoring survey remain the same, the annual repair

costs will differ based on the monitoring frequency employed, such that the cost for control of a fugitive emissions program increases as monitoring frequency increases because more repairs are performed. As we stated previously with regard to non-low production well sites, it is important to note that the model plants assume emissions do not change over time, therefore, the cost for control values presented in the TSD may overestimate the cost-effectiveness of each option after the initial monitoring period concludes and the percentage of fugitive emissions reaches a "steady state." For the reasons discussed below, we are not using the cost for control as the basis for the proposed fugitive emissions requirements for low production well sites.

We recognize that our analysis likely overestimates the emission reduction and therefore, the cost-effectiveness of each of the three monitoring frequencies due to several factors. First, similar to the cost analysis for non-low production well sites, the cost analysis for low production well sites does not take into account the declining percentages of fugitive emissions as a monitoring program continues. Second, as we have described previously, the number of each type of major production and processing equipment located at low production well sites may differ from that at non-low production well sites, and we are not certain this has been adequately taken into account with the limited data available[34] from the Fort Worth Study. The equipment that is present at a low production well site is typically designed for lower operating conditions, such as volume and pressure, therefore, the equipment may be smaller and composed of fewer fugitive emission components than those estimated in the model plants. As discussed in further detail in the TSD, we used the average major production and processing equipment counts from the Fort Worth Study as the basis for the low production model plants; however, because the Fort

[34] The site-specific data available in the Fort Worth Study is limited to approximately 300 natural gas well sites located near the City of Fort Worth, Texas. Most of the well sites consisted of dry gas, with no information available on oil well sites. We are uncertain the major production and processing equipment counts presented in this study are representative of well sites located in other areas of the country.

Worth Study does not provide component count data by equipment, we assigned the same average component counts per major equipment (*i.e.,* the same number of valves per separator as the number of valves per separator at non-low production well sites). Therefore, we are concerned that we have overestimated the fugitive emissions component counts for low production well sites. Additionally, the petitioners assert that the operating pressures are much lower for low production well sites than for non-low production well sites, and we do not have a mechanism to account for operating pressure changes in our model plants.[35] However, in section V.B.2 of this preamble, we discuss comments from petitioners stating that operating pressures may be driven, in part, by sales line pressures such that decreased production levels may not allow for operations below the gas sales line pressures. In such circumstances, the low production well site would need to produce at or above the relevant gas sales line pressure. This may result in decreased dump frequency or duration, and therefore, reduced periods of fugitive emissions during operation. While lower operating pressure and decreased dump frequency or duration would result in lower fugitive emissions, we do not have enough information to determine the likelihood of decreased operating pressure or decreased dump frequency or duration in order to account for them in our model plant analysis.

For the reasons stated above, we are unable to conclude that semiannual monitoring is cost-effective either when it is first implemented or later when the percentage of fugitive emissions components identified with fugitive emissions declines and approaches a steady state; we, therefore, do not believe it is appropriate to retain the semiannual monitoring approach or to propose a stepped approach (which would require semiannual monitoring for an initial period). While our analysis also overestimates the cost-effectiveness of annual monitoring, any such

[35] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682 and EPA-HQ-OAR-2010-0505-7685.

overestimate would be less compared to semiannual monitoring or the stepped approach. Furthermore, as discussed earlier in this subsection and later in the storage vessels subsection, we have observed a larger than expected number of controlled storage vessels claimed to be subject to the fugitive emissions requirements in 40 CFR 60.5397a, and many of them are located at low production well sites. Available data indicates that the frequency of fugitive emissions from controlled storage vessels may be much higher than those for other fugitive emissions components.[36] In light of the above, we are proposing to change the current monitoring frequency for low production well sites from semiannual monitoring to annual monitoring.

We are soliciting comment on the annual monitoring requirement for low production well sites. Additionally, we are soliciting data on the number of major production and processing equipment (*e.g.,* separators, heater treaters, glycol dehydrators, and storage vessels) and the number of fugitive emissions components (*e.g.,* valves, open-ended lines, and connectors) located at these well sites, as well as the operating pressures of these well sites considering gas sales line pressures and the number of major production and processing equipment located at the well site (*e.g.,* separators and heater treaters). Further, the EPA is proposing that low production well sites are defined as those well sites where the average combined oil and natural gas production is less than 15 boe per day averaged over the first 30 days of production. We are soliciting comment on the definition of a low production well site, including those where all the wells located on the well site have production below 15 boe per day. We are proposing specific recordkeeping and reporting requirements in 40 CFR 60.5420a, including a requirement to describe how the well site determined it is a low production well site. We are soliciting comment on the recordkeeping and reporting requirements, including alternative information that would

[36] See TSD for additional discussion of the fugitive emissions from storage vessels.

provide the combined production of oil and natural gas for the well site. In addition to soliciting comment on the annual monitoring frequency, we are also soliciting comment and supporting data on biennial monitoring and an exemption from fugitive emissions requirements at low production well sites, for well sites both with and without controlled storage vessels.

Monitoring Frequency for Compressor Stations. The 2016 NSPS OOOOa requires initial and quarterly monitoring of the collection of fugitive emissions components located at compressor stations. The EPA is not proposing changes to the quarterly monitoring frequency requirement for the collection of fugitive emissions components located at compressor stations. As noted in section V.B.1 of this preamble, we received petitions requesting less frequent monitoring, specifically semiannual monitoring for compressor stations.[37] Similar to well sites, the EPA received information from two stakeholders regarding fugitive emissions monitoring at compressor stations.[38,39] Some of the information provided the number of fugitive emissions and percentages of fugitive emissions components identified with fugitive emissions for 110 gathering and boosting compressor stations.[40] One stakeholder asserted the data provided regarding gathering and boosting stations would support changing the monitoring frequency for compressor stations to annual monitoring. Some of this data was specific to the required monitoring of the 2016 NSPS OOOOa, while other information was specific to monitoring requirements for various state programs or consent decrees. It was difficult for us to make any conclusions from the information, except to recognize that for at least one company, the average

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[37] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682, EPA-HQ-OAR-2010-0505-7685 and EPA-HQ-OAR-2010-0505-7686.
[38] See letter from GPA Midstream Association Re: GPA Midstream OOOOa White Paper Supplemental Information, March 5, 2018, located at Docket ID No. EPA-HQ-OAR-2017-0483.
[39] See memorandum *NSPS OOOOa Monitoring Case Study Presentation by Terence Trefiak with Target Emission Services* located at Docket ID No. EPA-HQ-OAR-2017-0483. March 13, 2018.
[40] See memorandum *EPA Analysis of Compressor Station Fugitive Emissions Monitoring Data Provided by GPA Midstream* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 17, 2018.

reported initial percentage of identified fugitive emissions is almost 1.5 percent, which is higher than the 1.18 percent used for our model plant calculations. Regardless, the EPA performed a sensitivity analysis using this data to understand how the cost of control would change if we applied the data provided to compressor stations, and reached the same conclusion that quarterly monitoring is cost-effective. Additional discussion on this analysis is included in the TSD.

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At this time, the EPA has not received data that supports changing the monitoring frequency to either semiannual or annual monitoring. In fact, the unique operating characteristics of compressor stations suggests quarterly monitoring, not less frequent monitoring, is more appropriate. The collection of fugitive emissions components located at compressor stations are subject to vibration and temperature cycling, which further supports more frequent monitoring. Studies indicate that components subject to vibration, high use, or temperature cycling are the most leak-prone."[41] The EPA best practices guide for LDAR states that more frequent monitoring should be implemented for components that contribute most to emissions.[42] Similarly, the Canadian Association of Petroleum Producers issued a best management practice for the management of fugitive emissions at upstream oil and gas facilities in 2007. That document states, "the equipment components most likely to leak should be screened most frequently. Additional information was also provided that suggested the operating mode of the compressor(s) located at the station was a key piece of information when detecting fugitive emissions. For instance, when compressors were in standby mode, the detected fugitive emissions were lower.[43] We had not previously considered that compressors may not be

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[41] Canadian Association of Petroleum Producers, "Best Management Practice. Management of Fugitive Emissions at Upstream Oil and Gas Facilities", January 2007.
[42] U.S. Environmental Protection Agency, "Leak Detection and Repair: A Best Practices Guide", EPA-305-D-07-001, October 2007.
[43] See memorandum *NSPS OOOOa Monitoring Case Study Presentation by Terence Trefiak with Target Emission Services* located at Docket ID No. EPA-HQ-OAR-2017-0483. March 13, 2018.

operating during the fugitive emissions survey, therefore, we are proposing that owners or operators keep a record of the operating mode of each compressor at the time of the monitoring survey, and a requirement that each compressor must be monitored at least once per calendar year when it is operating. This awareness of the impact operating mode of individual compressors may have on the occurrence of fugitive emissions further supports maintaining the quarterly monitoring frequency. For example, if the EPA moved to a semiannual or annual monitoring frequency, owners and operators may conduct fugitive emissions monitoring during scheduled maintenance periods such as the shoulder seasons, or other times when there is less demand on the station. This may artificially reflect lower fugitive emissions than if the monitoring occurred during peak seasons, thus decreasing the effectiveness of the program for controlling fugitive emissions.

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For the reasons stated above, the EPA is not proposing changes to the monitoring frequency for compressor stations. The EPA is soliciting comment and information to demonstrate that emission reductions, based on the current standards, can be achieved at less frequent monitoring intervals, such as semiannual and annual monitoring. The EPA is soliciting comment on the concept of requiring less frequent monitoring after an initial 2-year period (similar to the proposal for non-low production well sites), information to demonstrate the estimated emission reductions achieved by this program, and comment on any other pathways to less frequent monitoring. Additionally, we are soliciting data in order to understand how the percentage of identified fugitive emissions may change over time; the data should include the date of construction of the compressor station, information on when the compressor station began its fugitive program, the frequency of monitoring, an indication of the location of the

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compressor station, and how the surveys are performed, including the monitoring instrument used and the regulatory program followed.

The EPA is also soliciting information that can be used to evaluate if changes are necessary to the model plants. Specifically, the EPA requests information that has been collected from implementing fugitive monitoring programs. This information could demonstrate the actual equipment counts or fugitive emissions component counts at the compressor station, in relation to the number of fugitive emissions identified during each monitoring survey. Finally, the EPA solicits comment and information on costs associated with implementing a fugitive emissions monitoring program.

Well Sites and Compressor Stations Located on the Alaskan North Slope. On March 12, 2018, the EPA amended the 2016 NSPS OOOOa to include separate monitoring requirements for the collection of fugitive emissions components located at well sites located on the Alaskan North Slope.[44] As explained in that action, such separate requirements were warranted due to the area's extreme cold temperature, which is below the temperatures the monitoring instruments are designed to operate for approximately half of a year. The amended requirements for the collection of fugitive emissions components located at well sites located on the Alaskan North Slope specify that new well sites that startup production between September and March must conduct initial monitoring within 6 months of the startup of production[45] or by June 30, whichever is later, while well sites that startup production between April and August must comply with the 60-day initial monitoring requirement in the 2016 NSPS OOOOa. Similarly, well sites that are modified between September and March must conduct initial monitoring within 6 months of the first day of production for each collection of fugitive emissions

[44] 83 FR 10628.
[45] Startup of production is defined in 40 CFR 60.5430a.

components or by June 30, whichever is later. Further, all well sites located on the Alaskan North Slope that are subject to the fugitive emissions requirements must conduct annual monitoring, instead of the semiannual monitoring required for other well sites. Subsequent annual monitoring must be conducted at least 9 months apart.

Compressor stations located on the Alaskan North Slope experience the same extreme cold temperatures as the well sites located on the Alaskan North Slope. One petitioner[46] cautioned that the monitoring technology specified in the 2016 NSPS OOOOa (*i.e.*, optical gas imaging (OGI) and the instruments for Method 21) cannot reliably operate at well sites on the Alaskan North Slope for a significant portion of the year due to the lengthy period of extreme cold temperatures.[47] According to manufacturer specifications, OGI cameras, which the EPA identified in the 2016 NSPS OOOOa as the BSER for monitoring fugitive emissions at well sites, are not designed to operate at temperatures below ⁻ 4°F,[48] and the monitoring instruments for Method 21, which the 2016 NSPS OOOOa provides as an alternative to OGI, are not designed to operate below ⁺ 14°F.[49] One commenter provided data, and the EPA confirmed with its own analysis, that temperatures below 0° F are a common occurrence on the Alaskan North Slope between November and April.[50] In light of the above, there is no assurance that the initial and quarterly monitoring that must occur during that period of time are technically feasible for compressor stations located on the Alaskan North Slope. Additionally, while the 2016 NSPS

[46] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.
[47] See Docket ID No. EPA-HQ-OAR-2010-0505-12434.
[48] See FLIR Systems, Inc. product specifications for GF300/320 model OGI cameras at *http://www.flir.com/ogi/display/?id=55671*.
[49] See Thermo Fisher Scientific product specification for TVA-2020 at *https://assets.thermofisher.com/TFS-Assets/LSG/Specification-Sheets/EPM-TVA2020.pdf*.
[50] See information on average hourly temperatures from January 2010 to January 2018 at the weather station located at Deadhorse Alpine Airstrip, Alaska. Obtained from the National Oceanic and Atmospheric Administration (NOAA)'s National Centers for Environmental Information and summarized in Docket ID No. EPA-HQ-OAR-2010-0505-12505.

OOOOa provides a waiver from one quarterly monitoring event when the average temperature is below 0° F for two consecutive months, this waiver would not fully address the issues for compressor stations located on the Alaskan North Slope. As discussed above, temperatures are below 0° F between November and April, which spans across two quarters. The low temperature wavier, only allows missing one quarterly monitoring event. Based on available information, we have concluded that semiannual monitoring is not feasible for well sites, therefore, conducting three quarterly monitoring events is likewise not feasible for compressor stations. Therefore, we are proposing amendments to the fugitive emissions requirements in the 2016 NSPS OOOOa as they apply to compressor stations located on the Alaskan North Slope.

We are proposing to establish separate fugitive monitoring requirements for compressor stations located on the Alaskan North Slope because of the technical infeasibility issues with the operations of the monitoring instruments discussed above. Similar to well sites located on the Alaskan North Slope, we are proposing that new compressor stations that startup between September and March must conduct initial monitoring within 6 months of startup, or by June 30, whichever is later. Similarly, we are proposing that modified compressor stations located on the Alaskan North Slope that become modified between September and March must conduct initial monitoring within 6 months of the modification, or by June 30, whichever is later. Compressor stations that startup or are modified between April and August would meet the 60-day initial monitoring requirement in the 2016 NSPS OOOOa. However, as discussed in section V.B.3, we are soliciting comment on extending the time frame for conducting the initial monitoring for all well site and compressor station fugitive emissions components subject to the 2016 NSPS OOOOa, including those located on the Alaskan North Slope. Further, we are proposing that all compressor stations located on the Alaskan North Slope that are subject to the fugitive emissions

requirements must conduct annual monitoring. Subsequent annual monitoring must be conducted at least 9 months apart, but no more than 13 months apart.

As discussed in section V.B.3 of this preamble (Initial Monitoring for Well Sites and Compressor Stations), the EPA is soliciting comment on whether to extend the period for conducting initial monitoring for well sites and compressor stations because additional time is needed to complete installation of equipment. For the same reason, the EPA is soliciting comment on whether to extend the time frame for initial monitoring for well sites that start up production and compressor stations that start up between April and August, and for those that are modified during this period. Further discussion on this topic is included in section V.B.3 of this preamble, which describes the concerns raised and the timeframes suggested by petitioners (180 days) and EPA (90 days) to address such concerns. In addition to the information specified in that subsection, we are soliciting comments and information specific to the well sites and compressor stations located on the Alaskan North Slope regarding allowing additional time for the initial monitoring. Upon receiving and reviewing the relevant information, the EPA may conclude that amendment to extend the timeframe for conducting the initial monitoring is necessary for all or some well site and compressor station fugitive emissions components subject to the 2016 NSPS OOOOa, including those located on the Alaskan North Slope.

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One petitioner[51] requested that the EPA exempt well sites and compressor stations located on the Alaskan North Slope from fugitive emissions monitoring, similar to the exemptions from LDAR at natural gas processing plants provided in the 2012 NSPS OOOO and the 2016 NSPS OOOOa. The petitioner stated the reasons for applying an exemption to natural gas processing plants are also valid for well sites and compressor stations.

[51] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.

The EPA exempted natural gas processing plants from LDAR requirements when issuing 40 CFR part 60, subpart KKK, in 1985 (1985 NSPS KKK). At that time, we acknowledged "that there are several unique aspects to the operation of natural gas processing plants north of the Arctic Circle. Because of the unique aspects of natural gas processing plants north of the Arctic Circle, the increased costs to perform routine leak detection and repair may result in an unreasonable cost effectiveness."[52] We currently do not have sufficient information to suggest that the cost-effectiveness of the fugitive emissions requirements specific to well sites and compressor stations located on the Alaskan North Slope differ from the cost-effectiveness of the program generally. The information we do have related to the initial monitoring suggests that the average initial percentage of identified fugitive emissions for a well site located on the Alaskan North Slope is 2.38 percent.[53] Additionally, this information represents some of the highest reported percentages of identified fugitive emissions from the data set are from well sites located on the Alaskan North Slope. Therefore, we are not proposing to exempt well sites located on the Alaskan North Slope from the fugitive emissions requirements. However, we are soliciting data to support an analysis of the cost-effectiveness of fugitive emissions monitoring programs for well sites and compressor stations located on the Alaskan North Slope, including the cost associated with performing annual fugitive emissions monitoring and repairs. Specific information that distinguishes differences in cost realized by sites located on the Alaskan North Slope from our model plant estimates would be useful.

2. Modification

[52] "Equipment Leaks of VOC in Natural Gas Production Industry – Background Information for Promulgated Standards" EPA-450/3-82-024b, May 1985.
[53] See memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 17, 2018.

Modification of Well Sites. For the purposes of fugitive emissions components at a well site, a modification is defined in 40 CFR 60.5365a(i)(3) as (i) drilling a new well at an existing well site, (ii) hydraulically fracturing a well at an existing well site, or (iii) hydraulically refracturing a well at an existing well site. As the EPA explained in that rulemaking, these three activities, which are conducted to increase production, increase fugitive emissions at well sites in two ways. First, increased production will "generate additional emissions at the well sites. Some of these additional emissions will pass through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components)." 81 FR 35881. Second, additional fugitive emissions can also result from installation of additional equipment. As the EPA observed, "it is not uncommon that an increase in production would require additional equipment and, therefore, additional fugitive emission components at the well sites." *Id.*

As previously mentioned, in a letter dated April 18, 2017, the Administrator granted reconsideration of several aspects of the 2016 NSPS OOOOa, including applying the fugitive emissions requirements at 40 CFR 60.5397a to low production well sites.[54] The petitioner who raised this issue for reconsideration identified in its petition a perceived inconsistency between the EPA's justification for not exempting low production well sites from the fugitive emissions requirements and the EPA's rationale for the definition of modification for purposes of those same requirements.[55] This petitioner observed that it appeared the EPA relied on data indicating the same equipment counts are present at all well sites, regardless of production levels, to justify regulating fugitive emissions at low production well sites, while defining modification by events that increase production *(i.e.,* drilling a new well, hydraulic fracturing, or hydraulic refracturing),

[54] See Docket ID No. EPA-HQ-OAR-2010-0505-7730.
[55] See Docket ID No. EPA-HQ-OAR-2010-0505-7685.

which the EPA concludes will increase emissions whether or not there is change in component counts. The petitioner then stated that:

> "EPA's rationale, that fugitive emissions are a function of the number and types of equipment, and not operating parameters such as pressure and volume, is inconsistent with EPA's justification for what constitutes a "modification" for an existing well site. EPA assumes that fracturing or refracturing an existing well will increase emissions because of the additional production, i.e., the additional pressure and volume. EPA cannot ignore the laws of physics to the detriment of low production wells in one instance and then "honor" them in another context to eliminate an "emissions increase" requirement in the traditional definition of "modification."[56]

In addition to the issues raised regarding an inconsistency with our treatment of fugitive emissions from low production well sites and what constitutes a modification (as discussed in section V.B.1), several petitioners stated that hydraulically refracturing a well alone would not increase emissions from the fugitive emissions components and suggested that emissions would increase from a refractured well only if additional permanent equipment is also installed.[57] According to one petitioner,

> "[a] well that is refractured typically does not require additional production equipment and does not typically operate at a pressure higher than before the refracturing since that pressure is set by the gas gathering system pressure. Therefore, as long as a significant piece of process equipment is not constructed along with the refracture, there is no emissions increase and there is no 'modification' as defined in CFR Part 60.2."[58]

In light of the above, the EPA has provided a more detailed explanation below for the definition of modification of fugitive emissions components at well sites, including how an increase in production can increase fugitive emissions at well sites even without the addition of equipment, and therefore no addition of fugitive emissions components. The EPA has also re-

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[56] See Docket ID No. EPA-HQ-OAR-2010-0505-7685, page 6.
[57] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682, EPA-HQ-OAR-2010-0505-7685 and EPA-HQ-OAR-2010-0505-7686.
[58] Docket ID No. EPA-HQ-OAR-2010-0505-7682, p. 16.

evaluated its treatment of low production well sites, which is discussed in section V.B.1 of this preamble.

There is no dispute that an addition of processing equipment, and attendant fugitive emissions components, in conjunction with refracturing a well will result in a modification. Further, as explained in the 2016 NSPS OOOOa and in more detail below, an increase in the number of components is not the sole reason for an increase in fugitive emissions when there is an increase in production.

A well is refractured for the purpose of increasing production rates. An increase in the production rate necessitates, by definition, an increase in the molar flow rate. An increase in molar flow rate can be accomplished through an increase in operating pressure (and attendant mass per unit of volume) and/or volumetric flow rate. An increase in volumetric flow rate can be accomplished through an increase to the velocity of flow, an increase to cross-sectional area of the flow path, or, if flow is intermittent, an increase to the time duration of flow (e.g., duration of flow events or frequency of flow events). Increasing velocity of flow of production fluids through process equipment can only be accomplished through an increase in the pressure drop across the system. Where increased production throughput is routed through a system of production equipment that is not physically changed, the cross-sectional area of the flow path through the equipment does not change. Therefore, the increase in production rate requires an increase to either the operating pressure and/or the duration or frequency of flow events. Where operating pressure is increased, the pressure increase will increase the molar flow rate of fugitive emissions from leaking fugitive emission components. These increased emissions on components with existing fugitive emissions will occur even if the increased operating pressure does not result in additional components with fugitive emissions at existing design stress points,

which is an additional source of potential fugitive emissions increases. Increasing duration or frequency of flow events will not be an option unless flow is intermittent. Where flow is intermittent in the process and flow event duration or frequency is increased (*e.g.*, through longer dump events or more frequent dump events), additional molar flow rate will pass through components with fugitive emissions due to increased periods of flow through that component at the same pressure. Therefore, as was stated in the 2016 NSPS OOOOa preamble language, increased production will result in "[s]ome of these additional emissions [passing] through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components)." 81 FR 35881.

There is also a third instance in which increased production from modification of a well site could cause an increase in emissions from fugitive emissions components without additional equipment, and therefore, without additional fugitive emissions components. Absent additional stages of separation or an otherwise-accomplished decrease in the pressure at the final stage of separation prior to the storage vessels, increased production throughput to storage vessels increases the flash emissions at those storage vessels. Where storage vessels are affected facilities for purposes of this rule, the rule contains separate requirements for storage vessel covers and CVS to be designed and operated to route all emissions to a control device. However, where controlled storage vessels are not affected facilities because legally and practically enforceable permits limit the potential VOC emissions to below 6 tpy, the covers and CVS are included in the fugitives monitoring program for the well site as a fugitive emissions component. In either scenario, it is possible for increased throughput to these controlled storage vessels at a well site to exceed the design capacity of the vapor control system, which may result in additional emissions from storage vessel thief hatches or other openings.

For the reasons stated above, we continue to conclude that refracturing of an existing well will increase fugitive emissions. We solicit comments on our rationale described above. Specifically, we solicit comments and data on whether emissions from fugitive emissions components will increase following a refracture if the equipment counts and operating pressures remain the same. Further, we are soliciting comments and data about how changes in production may influence the operating pressures of the well site. Additionally, we are soliciting comment and data on whether an increase in pressure alone (without additional equipment) would result in more fugitive emissions (*e.g.*, cause new fugitive emissions that were not otherwise present or would result in an increase in the fugitive emissions from an already leaking fugitive emissions component). Finally, we are soliciting comment and information on other factors, such as changes in the gas gathering system, that may influence the operating pressures of the well site.

During the implementation of the 2016 NSPS OOOOa, several questions were raised regarding the modification of a separate tank battery for the purposes of fugitive emissions monitoring. The definition of well site in 40 CFR 60.5430a states, "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)." Stakeholders have commented to the EPA that there is confusion regarding when a modification of fugitive emissions components has occurred at a separate tank battery. Similar to the information from petitioners regarding modifications without a change in equipment or component counts at a well site, stakeholders have also claimed that sending process fluids from a new well or existing hydraulically fractured or refractured well that is not located at the separate tank battery will not necessarily increase the emissions from the fugitive emissions components at the separate tank battery. Instead,

stakeholders have suggested that emissions increase only when additional processing equipment, such as storage vessels, separators, or compressors, is installed in conjunction with the additional process fluids received from these off-site wells.

The EPA agrees that clarification is warranted regarding modifications of the collection of fugitive emissions components at well sites when the well site is a separate tank battery with no wells located at the tank battery. While the regulatory text is clear about what constitutes a modification when a well is located at the separate tank battery, the regulatory text is less clear when there are no wells at the tank battery. To clarify the definition of modifications for separate tank batteries, we are proposing specific amendments to clarify when a modification occurs at a well site, including a well site that is a separate tank battery. We are proposing to amend the language in 40 CFR 60.5365a(i) to add two additional instances to clarify when there is a modification to the collection of fugitive emissions components located at a separate tank battery, such as a centralized tank battery (which itself is a well site as defined in 40 CFR 60.5430a). First, when production from a new, hydraulically fractured, or hydraulically refractured well is sent to an existing separate tank battery, the collection of fugitive emissions components at the separate tank battery has been modified. Second, when a well site that is subject to fugitive emissions requirements removes the major production and processing equipment, such that it becomes a well head only well site, and sends the production to an existing separate tank battery, the collective fugitive components at that separate tank battery has modified. In both instances, a physical or operational change occurs at an existing separate tank battery because additional production from a well site is sent to that separate tank battery, and this change results in an increase in fugitive emissions at that tank battery. We are soliciting comment on these proposed amendments to the definition of modification of the collection of

fugitive emissions components located at a well site, including the treatment of separate tank batteries as well sites for the purposes of fugitive emissions requirements.

Modification of Compressor Stations. For the purposes of fugitive emissions components at a compressor station, a modification is defined in 40 CFR 60.5365a(j) as (1) the installation of an additional compressor at an existing compressor station or (2) the replacement of one or more compressors at an existing compressor station that results in a net increase in the total horsepower to drive the compressor(s) that are replaced at the compressor station. We are not proposing any changes to this definition; however, we are soliciting comment on whether the engine horsepower is the correct measure of increased emissions from the collection of fugitive emissions components.

Further, the EPA is clarifying the type of compressors that would trigger a modification for the purposes of fugitive emissions at a compressor station. In the preamble to the 2016 NSPS OOOOa, the EPA clarified that this definition refers to instances where "the design capacity and potential emissions of the compressor station would increase." 81 FR 35864. Therefore, it is possible that the addition of a compressor would not be considered a modification where the overall design capacity of the compressor station is not increased. For example, the addition of a vapor recovery unit (VRU) compressor, such as a screw or vane compressor, would not be a modification for purposes of the compressor station fugitive emissions standards. Adding a VRU compressor does not increase the overall design capacity of the compressor station for the following reasons. VRU compressors are installed to recover methane and VOC emissions; they are not designed to "move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage." Therefore, the addition of a VRU compressor does not increase the overall design capacity of a compressor station, and does not result in a modification

of the compressor station for the purposes of fugitive emissions monitoring. The EPA is not proposing a definition for compressor in this action because we disagree that one is needed given the explanation provided above related to the definition of compressor station, and because the 2016 NSPS OOOOa already contains definitions of centrifugal and reciprocating compressors, which are the only compressor affected facilities.

3. Initial Monitoring for Well Sites and Compressor Stations

The 2016 NSPS OOOOa requires completion of initial monitoring for well sites and compressor stations by June 3, 2017 or 60 days after startup, whichever is later. For well sites, the startup of production marks the beginning of the initial monitoring survey period for the collection of fugitive emissions components at a well site. Similarly, for compressor stations, the startup of the compressor station marks the beginning of the initial monitoring survey period.

Petitioners on the 2016 NSPS OOOOa have requested that the timing of fugitive emissions initial monitoring surveys be revised to allow for integration into existing monitoring programs.[59] One petitioner asserted that there are numerous challenges to setting up and implementing a fugitive monitoring program. The petitioner reported that even with the EPA's one-year phase-in allowance, there are initial inspection timing challenges (*e.g.*, because of the significant distances between oil and gas sites). Petitioners requested that the EPA consider allowing 180 days for the initial survey. According to the petitioners, allowing for 180 days would not result in significantly more emissions and that, on average, half of the sites would likely conduct their initial survey in less than 90 days and half would likely conduct their initial survey between 90 and 180 days.

[59] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682 and EPA-HQ-OAR-2010-0505-10791.

Between proposal and promulgation of the 2016 NSPS OOOOa, several industry comments recommended a 90-day time period (in lieu of the 30-day time period we initially proposed) to complete the initial survey to (1) address time and logistical capacities of oil and gas field crews and potential limited availability of monitoring contractors, (2) be consistent with the Ohio Environmental Protection Agency's General Air Permit for Oil and Gas Well Site Production Operations (General Permit 12.2), and (3) provide a more realistic time frame to perform an initial survey without potentially resulting in safety issues while initial oil and gas production and completion activities are taking place on the well pad.[60] Other industry comments were received requesting that the EPA allow the initial fugitive survey to occur within 180 days from startup of a new well site or compressor station to (1) be consistent with similar LDAR programs, such as NSPS KKK and NSPS OOOO (where leak detection is currently imposed at natural gas processing plants), and (2) allow owners or operators time to do a thorough check of all new equipment installations before the survey.[61] One of the commenters (also a petitioner) reported that 180 days is needed to work monitoring of the new or modified well into the next scheduled monitoring period that would include all the wells in the area.[62] They asserted that hiring third-party contractors to monitor one remote well site is inefficient and costly.

We have not received data indicating that initial monitoring cannot be completed within the currently required 60-day timeframe. We continue to conclude that initial monitoring needs to be completed in a timely manner after startup of production for well sites and the startup or modification for compressor stations to verify the proper installation of equipment and that waiting 180 days for initial monitoring is too long after the installation of equipment to verify its

[60] See Docket ID Nos. EPA-HQ-OAR-2010-0505-6808, EPA-HQ-OAR-2010-0505-6935 and EPA-HQ-OAR-2010-0505-6960.
[61] See Docket ID EPA-HQ-OAR-2010-0505-6857.
[62] See Docket ID EPA-HQ-OAR-2010-0505-6884.

proper installation. However, we are soliciting data that supports or refutes the claims by the petitioner that 180 days are necessary for proper installation of equipment before conducting initial monitoring would not result in significantly more emissions. Assuming we receive information that supports extending the initial monitoring deadline to give more time for installing equipment, we think these tasks may be completed in a shorter time frame than the suggested 180 days discussed above. We are, therefore, soliciting comment and supporting data for changing the initial monitoring deadline to 90 days from 60 days after the startup of production for well sites and the startup or modification for compressor stations. Specific data would need to outline the difficulties with completing initial monitoring within the 60 days required in the 2016 NSPS OOOOa.

We recognize that the 2016 NSPS OOOOa includes a waiver from quarterly monitoring at compressor stations after recognizing there are areas of the country that may experience temperatures below 0°F for a period of 60 days. However, as discussed in detail in section V.B.4, we are not sure there are areas of the country that would utilize this waiver. The EPA is soliciting comment on how cold weather may impact the ability to comply with the 60-day initial monitoring deadline for well sites and compressor stations.

4. Low Temperature Waivers

The EPA received several petitions to reconsider the temperature-based waiver for quarterly fugitive emissions monitoring at compressor stations because this waiver was added to the 2016 NSPS OOOOa without an opportunity for notice and comment. In the 2016 NSPS OOOOa, owners and operators are granted a waiver from one quarterly monitoring event at compressor stations if the average temperature is below 0°F for two consecutive quarters. 40 CFR 60.5397a(g)(5). In the preamble to the 2016 NSPS OOOOa we stated that the waiver was

included for two reasons: (1) there were concerns raised by commenters that extreme winter weather created risk for the safety of monitoring survey personnel and (2) the manufacturer specifications indicate that OGI cameras may not reliably operate at temperatures below 0°F. 80 FR 56668.

While the petitioners supported a temperature-based waiver, they requested that EPA consider extending the waiver to well sites because sustained low temperatures can also present an issue for semiannual monitoring at well sites in some regions, specifically the Alaskan North Slope.[63] The EPA is addressing the Alaskan North Slope separately in this action. The EPA has evaluated temperature data for areas in Wyoming and North Dakota, which are areas raised by petitioners as experiencing sustained inclement weather. These data, however, does not suggest that temperatures are below 0°F for a period of time that would prohibit compliance with semiannual monitoring at well sites outside of the Alaskan North Slope.[64] Therefore, we are not proposing to extend the temperature-based waiver for semiannual monitoring at well sites. However, the EPA is soliciting data that would indicate temperatures do present a compliance concern for these well sites.

Finally, one petitioner suggested the temperature should be raised to 32°F for the waiver for two reasons: (1) the instruments for Method 21 of Appendix A-7 of Part 60 are only certified at temperatures above 32°F, and (2) there are specific concerns related to the safety of monitoring personnel.[65] Regarding the first reason, the BSER for fugitive emissions monitoring is OGI monitoring; Method 21 is provided as an alternative in case some owners and operators prefer to

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[63] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.
[64] See information on average hourly temperatures from January 2010 to January 2018 at the weather station located at Pinedale, Wyoming and Williston, North Dakota. Obtained from the National Oceanic and Atmospheric Administration (NOAA)'s National Centers for Environmental Information and summarized in Docket ID No. EPA-HQ-OAR-2017-0483.
[65] See Docket ID No. EPA-HQ-OAR-2010-0505-7686.

use it. 80 FR 56638. Manufacturer specifications on OGI cameras state that the operating range is as low as ¯ 4°F. Further, the EPA has examined manufacturer specifications for Method 21 instruments and found that newer models of the toxic vapor analyzer are designed for operating temperatures above 14°F.[66] Regarding the second reason, while worker safety was raised as an issue, the petitioner did not provide specific data to allow the EPA to evaluate a change to the waiver based on worker safety. We are soliciting additional data that would support different temperature-based waivers for monitoring at compressor stations.

5. Repair Requirements

Repair. After detection of fugitive emissions, the 2016 NSPS OOOOa requires repair of these components within 30 days of detection of the fugitive emissions. Further, the owner or operator must resurvey the component within 30 days of the repair in order to verify successful repair. 40 CFR 60.5397a(h)(1) and (3).

Several questions were raised during implementation that required reconsideration of the repair requirements. Specifically, stakeholders asked about the situation where repairs were completed during the 30-day required timeframe but the resurvey identified the presence of fugitive emissions, indicating unsuccessful repair.

The EPA recognizes the requirements in the 2016 NSPS OOOOa may create an unintended noncompliance issue with the repair requirements. Therefore, we are proposing to amend the repair requirements to require a "first attempt at repair" within 30 days of detection of fugitive emissions, followed by a requirement that identified fugitive emissions be "repaired" within 60 days of detection. We are proposing definitions for "repaired" and "first attempt at repair" as related to the fugitive emissions requirements. The EPA is proposing to define

[66] See Thermo Fisher Scientific product specification for TVA-2020 at https://assets.thermofisher.com/TFS-Assets/LSG/Specification-Sheets/EPM-TVA2020.pdf.

"repaired," for purposes of fugitive emissions monitoring, as "fugitive emissions components are adjusted, replaced, or otherwise altered, in order to eliminate fugitive emissions as defined in 40 CFR 60.5397a of this subpart and is resurveyed as specified in 40 CFR 60.5397a(h)(4) and it is verified that emissions from the fugitive emissions components are below the applicable fugitive emissions definition." Additionally, we are proposing the definition for "first attempt at repair" for the purposes of fugitive emissions monitoring as "an action taken for the purpose of stopping or reducing fugitive emissions of methane or VOC 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; ensuring the thief hatch is properly seated or injecting lubricant into lubricated packing." These proposed definitions for "repaired" and "first attempt at repair" are specific to the fugitive emissions requirements and would not replace the definitions for "repaired" or "first attempt at repair" within the requirements for equipment leaks at onshore natural gas processing plants referenced in 40 CFR part 60, subpart VVa. We are soliciting comment on these proposed repair requirements and definitions.

Delay of Repair. As amended on March 12, 2018, the 2016 NSPS OOOOa allows for delay of repair if the repair is technically infeasible; requires 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. Repairs meeting one of these criteria must be completed during the next scheduled compressor station shutdown, well shutdown, or well shut-in; after a planned vent blowdown; or within 2 years, whichever is earlier. The amendment addressed the concerns associated with requiring repair during unscheduled or emergency events by removing such a requirement.

In addition to concerns with requiring repair during unscheduled or emergency events, several petitioners raised additional concerns with the provisions regarding the delay of repair for fugitive emissions components at well sites and compressor stations.[67] One petitioner stated that the 2-year delay should be reevaluated because no specific data was provided to support that deadline.[68] Further, other petitioners stated that blowdowns, shutdowns, and well shut-ins might not always involve depressurizing the specific equipment that needs repair. The EPA is soliciting comment on instances when equipment cannot be isolated during vent blowdowns, compressor station shutdowns, well shutdowns, and well shut-ins to allow for repair of components with fugitive emissions. Further, the EPA is soliciting comment and supporting information on the instances where delayed repairs cannot be conducted during any of the events listed in the rule and under what event or time frame delayed repairs can be conducted for those instances.

Finally, we are clarifying when a repair can be delayed. There are three circumstances when repair can be delayed: (1) when the repair is technically infeasible, (2) when the repair requires a vent blowdown, a compressor station shutdown, a well shut-in, or a well shutdown, and (3) when the repair is unsafe during operation of the unit.[69] The 2016 NSPS OOOOa requires an explanation of each repair that is delayed as well.[70] As discussed in section V.B.1, we have added 1 controlled storage vessel per model plant because when the controlled storage vessel is not subject to the control requirements in 40 CFR 60.5395a, the thief hatch and other openings are subject to fugitive emissions requirements, per the definition of fugitive emissions components in 40 CFR 60.5430a. The EPA believes that thief hatches on controlled storage

[67] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682, EPA-HQ-OAR-2010-0505-7683, and EPA-HQ-OAR-2010-0505-7686.
[68] See Docket ID No. EPA-HQ-OAR-2010-0505-7683.
[69] See 40 CFR 60.5397a(h)(2).
[70] See 40 CFR 60.5420a(b)(7)(ii)(J).

vessels which are part of the fugitive emissions program would not be subject to delay of repair under any of these circumstances; however, we are soliciting comment for any instance when delaying repair on a thief hatch may be necessary. We are concerned that questions may arise as to whether opening a thief hatch is considered a vent blowdown. While we do not consider this to constitute a vent blowdown, we are soliciting comment on whether clarification within the regulatory text is necessary for this point. We are also soliciting comment on the 2-year deadline for completion of delayed repairs.

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

Third-party equipment. In the 2016 NSPS OOOOa, all fugitive emissions components located at a well site, regardless of ownership, are subject to the monitoring and repair requirements for fugitive emissions in the 2016 NSPS OOOOa. As defined in 40 CFR 60.5430a, the term 'fugitive emissions component' means "any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including, but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411a, thief hatches or other openings on a controlled storage vessel not subject to §60.5395a, compressors, instruments, and meters" and the term '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." Several petitioners raised concerns that these definitions are too broad and requested that the EPA should exclude equipment that is owned and operated by a third-party.[71]

First, petitioners requested an exemption for equipment owned and operated by midstream companies because that equipment is owned by legally distinct entities, and

[71] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682 and EPA-HQ-OAR-2010-0505-7684.

applicability of the standards to midstream assets would be based solely on the actions of the upstream producers. Second, petitioners stated that the EPA is incorrect in suggesting that contractual agreements between upstream producers and midstream owners and operators would be appropriate for managing fugitive emissions monitoring and repair(s) at the well site. The petitioners stated that, due to the complexity of contractual agreements between different owners and operators at a well site, each individual owner or operator may need to develop and implement separate fugitive emissions monitoring programs. The petitioner further stated that doing so would add significant and unnecessary costs that the EPA did not consider.[72]

In the response to comment document for the 2016 NSPS OOOOa we stated that cooperative agreements could be used to resolve any fugitive emissions identified during surveys, but we acknowledged in the 2017 NODA that confusion remained over the applicability of the fugitive emissions requirements as they relate to ancillary midstream assets that are owned by legally distinct companies from the well site owner and operator and could have limited emissions. 82 FR 51798. In their comments on the 2017 NODA, one petitioner noted that since the components associated with the gas gathering and metering systems serve the "crucial commercial purpose in calculating gas accepted by the gathering company and the related revenue accounting", the midstream operators could not allow the production operators to access this equipment.[73] This petitioner further clarified that due to this limitation, the midstream operator would need to implement a separate fugitive emissions program for a limited number of components. Additionally, the petitioner stated there are significant practical issues with renegotiating contracts, especially as well sites are modified over time. We did not consider this issue during development of the 2016 NSPS OOOOa.

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[72] See Docket ID No. EPA-HQ-OAR-2010-0505-7684.
[73] See Docket ID No. EPA-HQ-OAR-2010-0505-13436.

In light of the concerns raised by the petitioners, the EPA is proposing to amend the definition of "well site", for the purposes of fugitive emissions monitoring, to exclude the flange upstream of the custody meter assembly, and fugitive emissions components located downstream of this flange. The EPA understands this custody meter is used effectively as the cash register for the well site and provides a clear separation for the equipment associated with production of the well site, and the equipment associated with putting the gas into the gas gathering system. Additionally, the proposed definition would exclude only a small number of fugitive emissions components, and we do not believe it would be cost-effective to require a separate fugitive emissions program for these components. We are also proposing a definition for the 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." We are limiting the exemption within the definition of a well site to the flange upstream of the custody meter because we are not aware of similar issues with monitoring other third-party equipment at a well site. The EPA is soliciting comment on this proposed change to the "well site" definition, the proposed definition of "custody meter", the proposed definition of "custody meter assembly", and suggestions for other ways which provide a clear separation to distinguish the third-party equipment described above at a well site, for the purposes of fugitive emissions monitoring.

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Applicability to Saltwater Disposal Wells. In addition to concerns about the definition of a "well site" as it relates to third party equipment, the EPA received feedback from industry seeking confirmation that a saltwater disposal well is not an injection well as the term is used in the definition for well site and, therefore, not subject to the fugitive emission standards at 40

CFR 60.5397a. They asserted that disposal wells are not injection wells and that the disposed liquid consists of water with insignificant amounts of stabilized skim oil that is never in vapor state at normal or elevated conditions. The commenters were concerned that, although they did not believe it was the EPA's intent to require fugitive emissions monitoring of saltwater disposal wells, they will nevertheless have to comply with those requirements because, as written, the definition of "well site" is ambiguous with respect to the status of saltwater disposal wells.

Deposits of oil and natural gas can be found in porous rocks and shale, where saltwater is also found. Oil and gas pumped out of the earth that is not pure enough for distribution because of saltwater and other chemicals/impurities go through a separation phase or are treated with chemicals that extract the impurities. After the oil or gas is treated, the water that remains (referred to as "saltwater") is subject to handling requirements.[74] Saltwater, or produced water, that results from bringing the oil and gas up to the surface (ejected from the well) during production operations is generally (1) recycled, (2) returned to the reservoir for fluid reinjection or (3) injected into underground porous rock formations not productive of oil or gas, and sealed above and below by unbroken, impermeable strata.[75] The third option is considered saltwater disposal (or oilfield wastewater disposal). Regulations for the disposal of this water vary from state to state, but the EPA monitors disposal to ensure ground water is not contaminated through Underground Injection Control (UIC) programs under the federal Safe Drinking Water Act for surface and groundwater protection. The EPA had not considered these UIC Class II oilfield wastewater disposal wells during the development of the fugitive emissions standards in the 2016 NSPS OOOOa.

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[74] http://www.tech-flo.net/salt-water-disposal.html.
[75] Barnett Shale Energy Education Council. *What are Saltwater Disposal Wells*? Air and Water Quality. http://www.bseec.org/what_are_saltwater_disposal_wells.

For the reasons stated below, we are proposing to exclude UIC Class II oilfield wastewater disposal wells from the well site definition and are proposing a definition for a UIC Class II oilfield wastewater disposal well to distinguish them from injection wells subject to the rule. It is our understanding that the storage vessels located at these disposal facilities have low methane and VOC emissions, and thus are not subject to the control requirements for storage vessels found in 40 CFR 60.5395a, do not require controls for permitting purposes, and would not be subject to fugitive emissions monitoring because they are uncontrolled. Further, it is our understanding that the number of fugitive emissions components at these facilities are typically low, including water pumps and a limited number of valves or connectors, which are expected to have negligible if any fugitive emissions. These proposed changes clarify the universe of well sites subject to the fugitive emissions standards. Our proposed definition for a "UIC Class II oilfield 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." Further, we are proposing that 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. We are soliciting comment on this proposed definition and on the proposed exemption for UIC Class II wastewater disposal wells and disposal facilities from fugitive emissions monitoring and repair, including data to support or refute our understanding that these sites have limited fugitive emissions components.

Definition of well site. As discussed in the sections regarding third-party equipment and saltwater disposal wells, the EPA is proposing to amend the definition of well site as follows:

> *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

fugitive emission standards at §60.5397a, a well site also means a separate tank battery surface site collection 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 and (2) the flange upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.

Startup of Production. The EPA defines the "startup of production" in the 2016 NSPS OOOOa 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." 40 CFR 60.5430a. For purposes of the fugitive emissions requirements in 40 CFR 60.5397a, the initial monitoring survey follows the startup of production. We received questions from stakeholders that suggested this definition would limit the fugitive emissions requirements to well sites with hydraulically fractured wells and not those with conventional wells. While the first trigger for modification is based on the drilling of a new well, regardless if it is hydraulically fractured or not, the definition of startup of production is linked to flowback, which is inherently an effect following hydraulic fracturing.

We are proposing to amend the definition of "startup of production" in this proposal to address how it relates to the fugitive emissions requirements. Specifically, we are proposing that, for the purposes of the fugitive monitoring requirements, 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." We are soliciting comment on this proposed definition change as it relates to wells that are not hydraulically fractured.

7. Closed Vent Systems (CVS) and Storage Vessel Thief Hatches

The requirements for CVS are specific to the type of affected facility that is associated with the CVS (*i.e.*, "routes to" the CVS). CVS receiving emissions from centrifugal compressor,

reciprocating compressor, and pneumatic pump affected facilities must be (a) initially and annually inspected visually for defects and (b) initially and annually monitored using Method 21 to verify operation at no detectable emissions (*i.e.*, an instrument reading less than 500 parts per million (ppm) above background concentration). In contrast, no instrument monitoring is required for CVS receiving emissions from storage vessel affected facilities and monthly auditory, visual, and olfactory (AVO) inspections must be performed. 40 CFR 60.5416a. Several petitioners have stated that the requirements for CVS associated with pneumatic pumps should be aligned with the requirements for CVS associated with storage vessels instead of the CVS requirements for centrifugal or reciprocating compressors.[76] In addition, these petitioners stated, though incorrectly, that pneumatic pumps are subject to OGI monitoring under the fugitive emissions requirements as well as the annual Method 21 requirement; the petitioners, therefore, assert that the Method 21 requirement is duplicative and burdensome. Pneumatic pumps are not fugitive emissions components because they vent as part of normal operation. Finally, stakeholders have requested streamlined and standardized requirements for all CVS, in place of equipment-specific requirements currently in the 2016 NSPS OOOOa. Specifically, the requirements are spread over multiple sections of the rule and vary based on the affected facility associated with the CVS as stated above, which the stakeholders have indicated creates confusion regarding compliance.

The EPA has received information from various stakeholders that overlapping requirements for these CVS and openings on controlled storage vessels may still exist due to state program requirements. Specifically, two stakeholders have informed us they are required to perform quarterly OGI monitoring on the CVS located at well sites under their state program in

[76] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682, EPA-HQ-OAR-2010-0505-7685 and EPA-HQ-OAR-2010-0505-7686.

addition to the annual Method 21 requirement on the same CVS for their affected facility pneumatic pumps as required by the 2016 NSPS OOOOa. We agree with the stakeholders that amendments are appropriate for the CVS requirements for pneumatic pumps

We are proposing to align the CVS monitoring requirements for affected facility pneumatic pumps with the CVS monitoring requirements for affected facility storage vessels. As stated by the petitioners, we agree that pneumatic pumps and storage vessels are commonly located at well sites and agree that having separate monitoring requirements for potentially shared CVS is overly burdensome and duplicative. This proposed amendment effectively requires monthly AVO monitoring for the CVS located at well sites because there are no affected facility reciprocating or centrifugal compressors located at well sites. We are soliciting comment on this proposed amendment for CVS on affected facility pneumatic pumps. Additionally, we are soliciting comment on other methods that could be employed as an alternative to the monthly AVO monitoring to ensure the CVS is operated with no detectable emissions. Finally, we are not proposing any changes to the CVS requirements for affected facility centrifugal compressors or reciprocating compressors.

8. Fugitive Emissions Monitoring Plan

The 2016 NSPS OOOOa requires that each fugitive emissions monitoring plan include a sitemap and a defined observation path.[77] As we are clarifying in this proposed action, these requirements were meant to apply only to owners and operators using OGI for monitoring surveys, not to owners and operators using Method 21. In addition to clarifying this intent, we are also proposing options that owners and operators using OGI for monitoring surveys can comply with in lieu of the observation path requirement.

[77] See 40 CFR 60.5397a(d)(1) and (2).

As we discussed in the preamble to the 2016 NSPS OOOOa, the purpose of the observation path is to ensure that the OGI operator visualizes all of the components that must be monitored. In a traditional monitoring scenario using Method 21, the owner or operator tags all of the equipment that must be monitored, and when the operator subsequently inspects the affected facility, the operator scans each component's tag and notes the component's instrument reading. The EPA realizes that this is a time-consuming practice that requires close contact with each component, whereas with OGI, the operator can be away from the components and still monitor several components simultaneously. The observation path[78] was intended to offer owners and operators an alternative to the traditional tagging approach while still providing assurance that the owner or operator has met the obligation to monitor all components. 81 FR 35860.

Petitions received on the 2016 NSPS OOOOa assert that there is no added benefit to including the sitemap and defined observation path in the fugitive emissions monitoring plan and that they should be removed.[79] Industry representatives report that, in many cases, sitemaps do not exist. They further report that there are significant added costs associated with the requirement to develop site-specific details for a sitemap and a defined observation path for each site and that there may be hundreds to thousands of different sites. These representatives express concern that sitemaps could also change, subjecting them to additional costs associated with revising the fugitive emissions monitoring plan without any added benefit. While we do think

[78] In the preamble to the 2016 NSPS OOOOa, we also noted that the purpose of using the term "observation path" was to clarify that the emphasis is on the field of view of the OGI instrument, not the physical location of the OGI operator. 81 FR 35860.
[79] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7686 and EPA-HQ-OAR-2010-0505-10791.

that it is necessary to revise monitoring plans when equipment at the site changes,[80] we generally expected these to be one-time requirements, unless additional equipment is added to the site. 81 FR 35860. The EPA is specifically seeking comment on whether this assumption is incorrect and, if not, we solicit information on the cost to develop and revise the sitemap, including the cost to document an observation path, the cost to revise a sitemap and observation path, and the frequency with which the sitemap and observation path need to be updated. We are also clarifying that plot plans can be substituted for sitemaps, as these two items serve the same function, *i.e.,* to provide information on the locations of equipment on site.

Industry representatives have also expressed concern that the fugitive emissions monitoring plan as written in 40 CFR 60.5397a(d) may cause enforcement issues in cases where the fugitive emissions monitoring plan is not followed exactly (specifically related to the defined observation path), even when the deviation is not critical and the monitoring plan is still effective. In response to public comments on the 2016 NSPS OOOOa, we stated that the elements required in the monitoring plan are necessary to judge the quality of the fugitive emissions survey, in light of the fact that the EPA does not have a standard method for use of OGI, but that we fully expected a trained and experienced camera operator to know when deviations from the standard monitoring plan are necessary and to make these deviations.[81] However, while deviations may not impact the camera's detection ability and can actually improve the detection ability, this does not mean that deviations from the monitoring plan should not be noted because this record provides valuable information to air agency reviewers on how

[80] As we stated in the preamble to the 2016 NSPS OOOOa, we do not expect facilities to create overly detailed process and instrumentation diagrams to describe the observation path. The observation path description could be a simple schematic diagram of the facility site or an aerial photograph of the facility site, as long as such a photograph clearly shows locations of the components and the OGI operator's walking path. 81 FR 35860

[81] See Docket ID No. EPA-HQ-OAR-2010-0505-7632, Chapter 4, page 4-708.

surveys are conducted and whether the deviations from the monitoring plan are adequate and warranted. We note that deviations from the monitoring plan are not necessarily deviations from the requirements of the rule.

While we are not proposing to remove the sitemap and observation path elements from the fugitive emissions monitoring plan, we are proposing two alternatives to address petitioner/industry representative concerns. First, in lieu of the defined observation path, we are proposing to add language to 40 CFR 60.5397a(d) that allows an owner or operator to describe how each type of equipment will be effectively monitored, including a description and location of the fugitive emissions components located on the equipment. The sitemap would include the locations of the pieces of equipment when complying with this option. Second, in lieu of meeting the sitemap and defined observation path requirements, we are proposing to add language to 40 CFR 60.5397a(d) to extend the inventory requirement that is currently in 40 CFR 60.5397a(d)(3) for when an owner or operator chooses to perform a survey with Method 21 as an option for owners and operators who perform surveys with OGI. We believe that both of these options provide assurances similar to the observation path that the owner or operator meets the requirement to visualize all components.

In summary, the EPA is retaining the requirements for the sitemap and observation path in the fugitive monitoring plan, but is also proposing two alternatives to these requirements. The EPA is soliciting comment on these proposed alternatives. Additionally, we are soliciting comment on other potential options that would serve the same functions as an observation path and sitemap. We are particularly interested in potential options that provide assurance that all regulated components have been monitored, how this information can be documented, and the costs of such alternative approaches.

C. Professional Engineer Certifications

The 2016 NSPS OOOOa requires that CVS used for routing emissions from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps, and storage vessels must have sufficient design and capacity to ensure that all emissions are routed to the control device. 40 CFR 60.5411a(d). This is accomplished through a design evaluation that must be certified by a "qualified professional engineer" (PE). Several petitioners requested reconsideration of the PE certification requirement because the EPA did not provide an evaluation of the costs associated with the certification.[82] Additionally, petitioners requested that the EPA allow alternatives to PE certification, such as engineering design reviews not necessarily conducted by a licensed PE.

The 2016 NSPS OOOOa also includes a technical infeasibility provision from the well site pneumatic pump requirements. However, the rule requires that such technical infeasibility be determined and certified by a "qualified professional engineer". 40 CFR 60.5393a(b)(5)(i). Petitioners objected to this additional certification, stating it results in additional costs and project delays, with no environmental benefits. Additionally, petitioners questioned the value of this requirement, claiming it is duplicative with the existing general duty obligations and certifying official's acknowledgment. Petitioners also stated that few companies have a sufficient number of in-house PEs, and requested that this requirement be broadened to allow alternatives to PE certification, including requiring engineering review and approval of all designs.

In the 2017 NODA, we requested information related to the availability of PEs to provide these certifications. Seven commenters provided information. Three commenters stated that there should be no limitation related to the availability of licensed PEs because in 2016 over 400,000

[82] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682, EPA-HQ-OAR-2010-0505-7685 and EPA-HQ-OAR-2010-0505-7686.

resident licenses were issued, and over 400,000 non-resident licenses were issued (a PE can hold both types of licenses).[83] One commenter cited a similar requirement in Colorado's regulation and stated that in response to the same concerns from the industry, Colorado found there was no basis for the claims about a lack of availability of PEs.[84] In contrast, four commenters stated difficulties with locating a PE willing to provide the certification, citing multiple concerns, including the certification statement included in the 2016 NSPS OOOOa and the certification of a portion of a system when the PE did not design the entire system.[85]

Commented [A16]: OMB comment 5/15

We have evaluated the concerns raised by petitioners regarding the additional burden of the PE certification for CVS design and pneumatic pump technical infeasibility. Further, the EPA agrees with commenters that in-house engineers may be more knowledgeable about site design and operation for both CVS and pneumatic pumps. In addition, the EPA acknowledges that, in the 2016 NSPS OOOOa, we had not analyzed the costs associated with the PE certification requirement and evaluated whether the improved environmental performance this requirement may achieve justifies the associated costs and other compliance burden. In this action, the EPA evaluated the costs associated with PE certification and certification by an in-house engineer. We estimated costs based on two scenarios: (1) requiring a PE certify the design and (2) allowing either a PE or an in-house engineer certify the design. We estimate that each PE certification would cost $547, while allowing use of in-house engineers would cost $358.[86] The EPA is soliciting comment on this cost estimate.

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[83] See Docket ID Nos. EPA-HQ-OAR-2010-0505-12386, EPA-HQ-OAR-2010-0505-12441, and EPA-HQ-OAR-2010-0505-12469.
[84] See Docket ID No. EPA-HQ-OAR-2010-0505-12469.
[85] See Docket ID Nos. EPA-HQ-OAR-2010-0505-12422, EPA-HQ-OAR-2010-0505-12424, EPA-HQ-OAR-2010-0505-12437, and EPA-HQ-OAR-2010-0505-12446.
[86] See the TSD for additional discussion of certification cost.

After reconsideration of these costs, the EPA is proposing to amend the certification requirements for CVS design and technical infeasibility for pneumatic pumps. Specifically, we are proposing to allow certification by either a PE or an in-house engineer with expertise on the design and operation of the CVS or pneumatic pump. We believe that an in-house engineer with knowledge of the design and operation of the CVS is capable of performing these certifications, regardless of licensure; however, we are soliciting comment on the use of other engineers with knowledge of the design and operation of the CVS that may be appropriate for this certification, such as third-party engineers. We continue to have a concern regarding the use of undersized or under designed CVS, which can result in pressure relief events from thief hatches and PRVs on the controlled storage vessels or CVS, thus allowing emissions to escape to the atmosphere uncontrolled. As stated in the 2013 NSPS OOOO Oil and Natural Gas Sector: Reconsideration of Certain Provisions of New Source Performance Standards, "Improper design or operation of the storage vessel and its control system can result in occurrences where peak flow overwhelms the storage vessel and its capture systems, resulting in emissions that do not reach the control device, effectively reducing the control efficiency. We believe that it is essential that operators employ properly designed, sized, and operated storage vessels to achieve effective emissions control." 78 FR 22136. This proposed amendment will still ensure these systems are evaluated and certified by engineers with expert knowledge of their operation.

D. Alternative Means of Emission Limitation (AMEL)

The 2016 NSPS OOOOa contains provisions for owners and operators to request an AMEL for specific work practice standards in the rule, covering well completions, reciprocating compressors, and the collection of fugitive emissions components at well sites and compressor stations. An owner or operator can request an AMEL by submitting data that demonstrate the

alternative will achieve at least equivalent emission reductions as the requirements in the rule, among other requirements such as initial and on-going compliance monitoring. The specific requirements for this request are outlined in 40 CFR 60.5398a. For the 2016 NSPS OOOOa, these alternatives could be based on emerging technologies (*e.g.*, for fugitive emissions, technologies other than OGI or Method 21) or requirements under state or local programs.

We are proposing to amend the language in 40 CFR 60.5398a for incorporation of emerging technologies, and adding a separate section at 40 CFR 60.5399a to take into account existing state programs as discussed in further detail in the sections below.

1. Incorporating Emerging Technologies

As discussed in the 2016 NSPS OOOOa, the EPA recognizes that new technologies are expected to enter the market in the near future that will locate the source of emissions sooner and at lower levels than current technology. While the EPA established a foundation for approving the use of emerging technologies in the final rule, several stakeholders have identified a need to streamline the process for requesting and approving an AMEL for individual affected sources, such as well completions, compressors, and the collection of fugitive emissions components located at a well site or at a compressor station. As promulgated in the 2016 NSPS OOOOa, each AMEL request must be submitted using site-specific information, which could result in the same owner or operator submitting identical requests for multiple affected facilities. We are clarifying that an individual application may include the same technology for multiple sites, provided the required information is provided for each site and site-specific variations to the procedures are addressed in the application. The application must provide a demonstration of equivalency and the emission reductions achieved for each site included in the application. The EPA is also proposing specific changes to the AMEL process as it relates to emerging technologies to

address this issue. Specifically, we are proposing to allow owners or operators to apply for an AMEL, on their own or in conjunction with manufacturers or vendors, and trade associations, that incorporates the use of alternative technologies, techniques, or processes, along with compliance monitoring provisions to ensure continuous compliance other than those identified in the 2016 NSPS OOOOa work practice standards. We are not changing the requirement that AMELs must be site-specific because we are aware of the variability of this sector and are concerned that the procedures for a specific technology may need to be adjusted based on site-specific conditions (*e.g.*, gas compositions, allowable emissions, or landscape). Therefore, we expect that applications for these AMEL will include site-specific procedures for ensuring continuous compliance of the emission reductions to be demonstrated as equivalent. For this reason, we are not proposing to allow a manufacturer, vendor, or trade association to apply for an AMEL without an owner or operator. Additionally, we are proposing that field data can be supplemented with test data, modeling analyses and other documentation, provided the field data still provides information related to seasonal variations. For the purposes of fugitive emissions requirements, the application must demonstrate that the technology is able to detect emissions beyond those allowed, such as pneumatic controllers. We are soliciting comment on the proposed revisions to the application requirements for technology-based AMEL.

2. Incorporating State Programs

In addition to recognizing potential emerging technologies, the EPA evaluated existing state and local fugitive emissions programs during the development of the 2016 NSPS OOOOa for purposes of establishing AMEL. The EPA was unable to conclude that any state program as a whole would reflect what we identified as BSER in the 2016 NSPS OOOOa due to the differences in the sources covered and the specific requirements. However, the 2016 NSPS

OOOOa allowed owners and operators to use the AMEL process to allow use of existing state or local programs. 81 FR 35871. Petitioners and states have raised specific questions about the practicality of the AMEL process as it relates to the incorporation of state programs.[87] For instance, one state has notified the EPA that since the ability to make an AMEL request is limited to owners and operators at the individual site level, it is possible that the EPA would have over 300 identical applications from various owners and operators wanting to use the same state program at their affected facilities. Believing that there may be opportunities to streamline the process, ensure compliance, and reduce regulatory burdens, the EPA continued its evaluation of existing state fugitive emissions programs after promulgating the 2016 NSPS OOOOa. Based on this evaluation, the EPA is proposing certain existing state requirements as alternatives to specified aspects (*e.g.*, monitoring, repair, and recordkeeping) of the fugitive emissions requirements for well sites and compressor stations.

To date, the EPA has evaluated 14 existing state programs for comparable or equivalent standards related to the fugitive emissions requirements in 40 CFR 60.5397a and the specific amendments in this proposal. For this evaluation, we compared the fugitive emissions components covered by the state programs, monitoring instruments, leak or fugitive emissions definitions, monitoring frequencies, repair requirements, and recordkeeping to the fugitive emissions requirements proposed in this action.[88] We did not include an evaluation of monitoring plans or reporting requirements because we are not proposing any alternative standards for these aspects of the fugitive emissions requirements. Through this evaluation, we have identified

[87] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682, EPA-HQ-OAR-2010-0505-7685 and EPA-HQ-OAR-2010-0505-7686.
[88] See memorandum *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 12, 2018.

aspects of certain existing state fugitive emissions programs that we find to be at least equivalent to the proposed amendments in this action.[89] For instance, we have evaluated the lists of affected fugitive components, monitoring instrument(s), fugitive definition(s), monitoring frequency, repair deadlines, delay of repair provisions, and recordkeeping of the programs reviewed. In most of the programs, the affected fugitive components were different than our definition of fugitive emissions component, therefore, we are proposing alternative standards that also require the owner or operator to survey our entire list of fugitive emissions components, regardless of whether they are affected components in the state program. Additionally, we evaluated monitoring instruments, frequencies, and fugitive definitions in conjunction with each other. Where monitoring is more frequent, we are proposing that a different fugitive definition could be appropriate. For instance, the standards in the California Code of Regulations, title 17, sections 95665-95667 require quarterly monitoring using Method 21 with a fugitive definition of 1,000 ppm while this proposal requires annual or stepped monitoring with a fugitive definition of 500 ppm if Method 21 is the chosen monitoring instrument. The EPA believes that more frequent monitoring warrants allowance of a higher fugitive definition because larger fugitive emissions will be found faster and repaired sooner, thus reducing the overall length of the emission event. Additional information related to the specific evaluation of programs is available in the memorandum *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa*, located at Docket ID No. EPA-HQ-OAR-2017-0483.

Based on this evaluation, we are proposing combining those aspects of the state requirements to formulate alternatives to the relevant portions of the fugitive emissions standards

[89] California, Colorado, Ohio, Pennsylvania, Texas, and Utah.

for the collection of fugitive emissions components located at either well sites or compressor stations. The specific states for which we are proposing alternative standards are California, Colorado, Ohio, and Pennsylvania for both well sites and compressor stations, and Texas and Utah for well sites only~~, and Pennsylvania for compressor stations only~~. We have not determined whether Pennsylvania's Exemption No. 38 for well sites should be included in the alternative standards, and we are soliciting comment on whether a state would revert to its original program once the monitoring frequency for well sites is reduced. While we evaluated the current consent decree[90] that the state of North Dakota has developed for well sites, we are not proposing alternative standards related to those requirements because by their nature, consent decrees are negotiated terms for non-compliance and contain an expiration date, after which sources return to compliance with the underlying regulatory provisions, permit terms, etc. Further, inclusion of settlement terms from a consent decree as an alternative standard would essentially endorse regulation through enforcement as a pathway to establishment of alternative standards. For all of these reasons, the EPA believes that evaluation of settlement agreement terms reached through negotiated resolution to an enforcement action would be an inappropriate basis from which to establish alternative standards for regulations promulgated through notice and comment rulemaking. Additionally, we are identifying the specific effective date of the individual state programs to specify which version of the state programs is being proposed as alternative standards because the state programs may change over time, and our evaluation is only valid for the current version of these programs. If in the future any of these programs are amended, the states can utilize the proposed application procedure discussed below.

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[90] See North Dakota Consent Decree 10.19.16, attachment to the memorandum *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa*. April 12, 2018, in Docket ID No. EPA-HQ-OAR-2017-0483.

The proposed alternative fugitive emissions standards include alternatives for monitoring frequencies, repair deadlines, and recordkeeping. The requirements for the monitoring plan found in 40 CFR 60.5397a(c) and (d) would still apply. In fact, the owner or operator would indicate through this monitoring plan that they have elected the alternative and would base the monitoring plan on the specific requirements from the state, local, or tribal program that is being adopted. Compliance would be evaluated against the specified requirements in the alternative fugitive emissions standards as incorporated in the monitoring plan. Further, we are proposing to require notification that the owner or operator has elected to comply with the applicable alternative fugitive emissions standards for the state in which the well site or compressor station is located. We are proposing that this notification is made at least 90 days prior to adopting an alternative fugitive emissions standard. We are soliciting comment on this notification requirement, including the appropriateness of the use of 90 days prior to adoption of the alternative standards.

In this action we are proposing a new section, in proposed 40 CFR 60.5399a, to include these state requirements that qualify as alternative fugitive emissions standards. The proposed section also includes a framework for the application and inclusion of additional existing state fugitive emissions standards as alternatives to the fugitive emissions requirements or future revisions to programs already proposed as alternative standards. Under our proposal, such applicants would include, but not be limited to, individuals, corporations, partnerships, associations, states, or municipalities. The proposed requirements for the application include specific information about the monitoring instrument (including monitoring procedures), monitoring frequency, leak or fugitive emissions definition, and repair requirements. We are soliciting comment on the proposed application requirements, the proposed alternative fugitive

emissions standards (including compliance monitoring), and information to support the inclusion of additional alternative fugitive emissions standards.

E. Other Reconsideration Issues Being Addressed

1. Well Completions

Location of a Separator During Flowback. The 2016 NSPS OOOOa requires the owner or operator to have a separator onsite during the entirety of the flowback period. 40 CFR 60.5375a(a)(1)(iii). However, several petitioners indicated that it is not clear whether the term "onsite" refers to the specific well site where the well completion is taking place.[91] Our intent was that the separator be located in close enough proximity to the well that it could be utilized as soon as sufficient flowback is present for the separator to function. Close proximity could be either onsite or nearby, as we explained in the preamble to the 2016 NSPS OOOOa, "We anticipate a subcategory 1 well to be producing or near other producing wells. We therefore anticipate REC equipment (including separators) to be onsite or nearby, or that any separator brought onsite or nearby can be put to use." 81 FR 35852. Thus, our intent was that the separator may be located at the well site or near to the well site so that it is able to commence separation flowback, as required by the rule. Locations "near" or "nearby" may include a centralized facility or well pad that services the well which is used to conduct the completion of the well affected facility. In order to alleviate concerns that the separator must be located on the well site, we are proposing to amend 40 CFR 60.5375a(a)(1)(iii) to clarify the location of the separator.

Screenouts and Coil Tubing Cleanouts. Petitioners requested clarification as to whether screenouts and coil tubing cleanouts are regulated as part of flowback. Petitioners asserted that these are necessary processes performed during hydraulic fracturing that are not associated with

[91] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682 and EPA-HQ-OAR-2010-0505-7686.

flowback.[92] In November 2016, the EPA responded to a letter from API seeking clarification on this issue, stating, "any releases of gas or vapor during 'screenouts' and 'coil tubing cleanouts,' which occur during the initial flowback stage are not subject to control under section 60.5375a".[93] However, we have further assessed this topic and believe that the guidance we issued was incorrect. In the preamble to the final 2014 amendments, we stated regarding flowback: "…the first stage would begin with the first flowback from the well following hydraulic fracturing or refracturing, and would be characterized by high volumetric flow…" 79 FR 79024. In some situations, screenouts or coil tubing cleanouts may be necessary in order to remove proppant (sand) from the well so that high volumetric flow can occur, marking the beginning of the initial flowback stage. Therefore, screenouts and coil tubing cleanouts are not a part of flowback; rather, they are functional processes that allow for flowback to begin. It should be noted that this is consistent with the definition of hydraulic fracturing, which we stated requires high rate, extended flowback to expel fracture fluids and solids during completions. 40 CFR 60.5430a. For the reasons stated above, the November 2016 letter incorrectly states that screenouts and coil tubing cleanouts occur during the initial flowback stage. To clarify this point, we are proposing to revise the definition of flowback to expressly exclude these processes to avoid any future confusion. In addition, we are proposing definitions for these processes. A screenout is the first attempt to clear proppant from the wellbore. It involves flowing the well to a fracture tank in order to achieve maximum velocity and carry the proppant out of the well. If a screenout is unsuccessful in clearing the proppant from the wellbore, then a coil tubing cleanout is conducted. This involves running a string of coil tubing to the packed proppant and jetting the well to dislodge the proppant and provide sufficient lift energy to flow it to the surface. It is after

[92] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.
[93] See Docket ID No. EPA-HQ-OAR-2010-0505-7722.

these processes that flowback begins and, subsequently, production. The EPA solicits comment on the proposed definitions for these processes.

Plug Drill-Outs. A plug drill-out is the removal of a plug (or plugs) that was used to conduct hydraulic fracturing in different sections of the well. Plug drill-outs are also functional processes that are necessary in order for flowback to begin. Therefore, the EPA is similarly proposing to exclude these processes from the definition of flowback.

Flowback Routed Through Permanent Separators. The EPA is proposing to streamline reporting and recordkeeping requirements for flowback routed through permanent separators to reduce burden on the regulated community. We consider a permanent separator to be one that handles flowback from a well or wells beginning when the flowback period begins and continuing to the startup of production. When routing flowback through permanent separators, some reporting and recordkeeping elements associated with well completions (*e.g.*, information about when a separator is hooked up or disconnected) become unnecessary because the separator is already connected to the well at the onset of flowback. In these situations, there is no initial flowback stage, and the separation flowback stage begins. Therefore, the EPA is proposing that operators do not need to record or report the date and time of each attempt to direct flowback to a separator for these situations. These streamlined recordkeeping and reporting requirements would not apply in situations where flowback is not routed through a permanent separator. The EPA is soliciting comments on these proposed revisions and additional ways to streamline reporting and recordkeeping.

2. Onshore Natural Gas Processing Plants

Capital Expenditure. We are proposing to correct the definition of "capital expenditure" promulgated at 40 CFR 60.5430a by replacing the reference to the year 2011 with the year 2015

in the formula in paragraph (2) of the definition. The definition of "capital expenditure" was among the issues related to 40 CFR part 60, subpart OOOO that the EPA reconsidered and addressed in the 2016 NSPS OOOOa. That definition is relevant to the equipment leaks standards for onshore natural gas processing plants that were originally promulgated in 1985 in 40 CFR part 60, subpart KKK, updated in 2012 in 40 CFR part 60, subpart OOOO, and carried over in 2016 in 40 CFR part 60, subpart OOOOa. As explained in the memorandum *Alternative Method for Determining Capital Expenditures (Thomas W. Rhoads to Docket A-80-44, July 21, 1983)*, located at Docket ID No. EPA-HQ-OAR-2017-0483. As explained in that memorandum, this method was developed to allow a facility to approximate the original costs of the facility using the replacement costs and the inflation index and therefore, providing an alternative method to the definition of "capital expenditure" in 40 CFR part 60, subpart A ("General Provisions").[94] The value for "Y" (the percent of replacement cost) is designed to take into account the age of the facility. Therefore, the replacement cost for a new facility should be the same as the original cost, or the value of "Y" should be closer to 1 for new facilities. Because the 2016 NSPS OOOOa applies to new sources constructed, reconstructed, or modified after September 18, 2015, the base year of 2015 is the correct year to reflect the age of the facility in this calculation.

However, for sources that commenced construction between January 1, 2015, and September 18, 2015, there is an issue using the value of "2015" because it results in a "zero" value for "X" for which there is no logarithmic solution. The EPA is, therefore, amending the definition so that the value of "Y" equals 1 if the affected process unit was constructed in 2015. The proposed amendment would address the mathematical issue for affected sources constructed

[94] See also *Equipment Leaks of VOC in Natural Gas Production Industry – Background for Promulgated Standards*, EPA-450/3-82-024b, May 1985, at 9-1.

in 2015 whiling leaving the calculation method intact for other affected sources. We are soliciting comment on the proposed amendment to the equation.

Notwithstanding this proposed amendment, as indicated above, the equation was developed as an alternative to the General Provisions definition of "capital expenditure." Since the General Provisions definition also applies, if calculation issues arise when applying the 2016 NSPS OOOOa equation, facilities should use the General Provisions to calculate capital expenditure. Facilities can also contact the EPA for guidance on how to apply the General Provisions definition for "capital expenditure" evaluations if necessary by utilizing 40 CFR 60.5 (Determination of construction or modification).

In addition, the EPA is soliciting comment and information to help inform us whether the current capital expenditure definition should be revised based on a ratio of consumer price indices (CPI), as requested by two petitioners.[95] Petitioners indicated that calculation of "capital expenditure" was designed to account for inflation. In supporting documentation provided from one petitioner[96] a plot of values prior to 1982 demonstrates a logarithmic function, which directly correlates to the CPI for the years 1950 through 1982. This was the information on which the "capital expenditure" equation was based. However, as described by the petitioners, the CPI takes a more linear function post-1982, while the "capital expenditure" equation remains with a logarithmic function. In practice, this could mean that the "P" value would be lower using the "capital expenditure" equation, thus resulting in modifications at lower expenditures than if the CPI were used. While we are proposing to update the existing equation with the corrected base year date of 2015, we are also soliciting comment on changing the calculation for the value of

[95] See Docket ID Nos. EPA-HQ-OAR-2010-0505-7682 and EPA-HQ-OAR-2010-0505-7684.
[96] See *GPA Midstream New Source Performance Standards ("NSPS") Subpart OOOOa Petition for Review Technical Issues* located at Docket ID No. EPA-HQ-OAR-2010-0505-12361. March 1, 2017.

"Y" using the CPI. Specifically, we are soliciting comment on the petitioner's suggestion that the value for "Y" should be calculated using the CPI of the date of construction or reconstruction divided by the CPI of the date of component price data, or "CPI_N/CPI_{PD}".

VI. Implementation Improvements

Following publication of the 2016 NSPS OOOOa, we subsequently determined, following review of petitions and discussions with affected parties, that the final rule warrants correction and clarification in certain areas. Each of these areas is discussed below.

A. Reciprocating Compressors

The 2016 NSPS OOOOa includes an alternative to the work practice standards for reciprocating compressors. Operators may choose to gather rod packing emissions using a collection system that operates under negative pressure and then route emissions to a process via a CVS, as opposed to replacing the rod packing every 26,000 hours or 36 months. During the comment period for the proposal for the 2016 NSPS OOOOa, the EPA received feedback from various stakeholders, who noted that there were safety concerns with requiring the rod packing emissions to be collected under negative pressure. Specifically, commenters stated that operating the collection system under negative pressure may inadvertently introduce oxygen into the system.[97] In response to comments, the EPA stated that operation of the collection system under negative pressure was necessary in order to appropriately capture emissions.[98] However, the EPA did not respond to comments regarding safety concerns and is soliciting comment on the requirement that rod packing emissions be collected under negative pressure. The EPA is soliciting comment and supporting data on capture systems which are at least equivalent to the

[97] See Docket ID No. EPA-HQ-OAR-2010-0505-6884.
[98] See Docket ID No. EPA-HQ-OAR-2010-0505-7632, Chapter 7, page 7-37.

current systems and which could negate the necessity to capture emissions under negative pressure.

B. Storage Vessels

Pursuant to 40 CFR 60.5365a(e), owners and operators must calculate potential emissions from storage vessels in order to determine if control requirements apply. This calculation is based on the "maximum average daily throughput". During implementation of the 2016 NSPS OOOOa, several stakeholders requested clarification regarding this calculation. Specifically, the stakeholders have expressed confusion about what value constitutes the "maximum average daily throughput." This value was intended to represent the maximum daily production rate in the first 30-day period to each storage vessel. The EPA stated in its Response to Comments on the 2013 amendments to subpart OOOO, "we believe that the estimate of potential VOC emissions should be determined based on maximum emissions during the 30-day period rather than average emissions over that period".[99] We are proposing to remove the word "average" from this term to clarify the term applies to the maximum daily throughput. Additionally, we are clarifying how the "maximum daily throughput" must be calculated. Specifically, where a storage vessel is equipped with automation that measures and records liquid level in a data historian such that you can determine the throughput to the storage vessel for each day during the first 30 days of production, you must use the maximum value measured for any one of the 30 days. We understand that some storage vessels may not be equipped with automation and may not have daily measurements taken through other means. In such circumstances, we believe that the liquid height, and therefore volume, in the storage vessel would be measured at a minimum at the start and completion of loadout of liquids from the storage vessel. Frequency of loadout from each

[99] See Docket ID No. EPA-HQ-OAR-2010-0505-4639.

storage vessel (*i.e.,* "turnover rate") will vary depending on company or site-specific operations. Therefore, it is possible that a storage vessel could have multiple turnovers during the first 30-days of production. Where this occurs, you must determine the daily throughput for each of those periods and use the maximum of those throughput values to calculate the potential emissions from the storage vessel. We recognize that calculating daily throughput based on liquid level measurements at the beginning and end of a turnover period will necessarily average production throughput to the storage vessel over the number of days in the turnover period. However, recognizing that production declines, we are clarifying that this calculation, based on the first 30-days of production, represents the maximum potential emissions. We are soliciting comment on this clarification.

Further, inspection data and compliance reports for the 2016 NSPS OOOOa indicate that many operators determined that few or no storage vessels are affected facilities under the 2016 NSPS OOOOa. For example, review of the 2016 NSPS OOOOa compliance reports indicates that some operators may be incorrectly averaging emissions across storage tanks in tank batteries when determining the potential for VOC emissions. Both the 2012 NSPS OOOO and 2016 NSPS OOOOa specify that a storage vessel affected facility is "a single storage vessel" that "has the potential for VOC emissions equal to or greater than 6 tpy." 40 CFR 60.5365(e) and 60.5365a(e). In prior rulemakings, the EPA explained that storage vessel emission estimation methods for the potential for VOC emissions generally require information on both the composition and volumetric rate of the liquid entering the storage vessel, where the volumetric throughput is frequently calculated by recording the volume of liquid collected from the receiving vessel(s) over time. 79 FR 79026. Because the 2012 NSPS OOOO and 2016 NSPS OOOOa define the affected facility as "a single storage vessel," the determination of the potential for VOC

emissions must be based on the liquid throughput of each "single storage vessel," even where the storage vessel is part of a tank battery. Operators should ensure that the determination of the potential for VOC emissions reflects each storage vessel's actual configuration and operational characteristics. Furthermore, if a storage vessel's configuration or operational characteristics are intended to avoid the 2012 NSPS OOOO or 2016 NSPS OOOOa applicability, the NSPS General Provisions on circumvention at 40 CFR 60.12 may provide grounds for state or federal enforcement. Similarly, the EPA notes that affected facility determinations are allowed to account for legally and practically enforceable limits in determining the potential for VOC emissions for a storage vessel. However, 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. Given the potential for recurring emissions from controlled storage vessel thief hatches or other opening owing to operation and maintenance performance even where adequate design has been verified,[100] any limit on capture and control efficiency from storage vessels must include sufficient monitoring to timely identify and repair emissions from storage vessels to ensure the limit on capture and control efficiency is consistently achieved.

Where a storage vessel is part of a tank battery, some operators appear to derive the maximum daily throughput of a storage vessel in a battery by using the throughput to the entire battery (by using records of liquids collected from the battery over time) and dividing that figure by the number of storage vessels in the battery. This approach for determining a storage vessel's

[100] *Analysis of Consent Decree Reports from Noble Energy, Inc. as to Emissions Observations from Thief Hatches or Other Openings on Controlled Storage Vessels; Oil and Natural Gas Sector: Emission Standards for New, Reconstructed and Modified Sources Reconsideration – SAN 5719.8* located at Docket ID No. EPA-HQ-OAR-2017-0483.

maximum daily throughput is incorrect for certain operational configurations. For instance, where a tank battery is operated such that all pressurized liquids from the separator initially flow to only one storage vessel, and then overflow to the next, and so on (*i.e.,* in series or series flow), the first individual storage vessel's throughput would be the entire battery's throughput, not the entire battery's throughput apportioned evenly among the storage vessels. Dividing an entire battery's throughput by the number of storage vessels in the battery would greatly underestimate flash emissions from the first storage vessel connected in series, which is where liquid pressure drops from separator pressure to atmospheric pressure. However, such division could be appropriate where all liquids flow through a splitter system in a common header that ensures that all liquids initially flow in equal amounts to all storage vessels in a tank battery at all times since the liquid pressure drop would occur equally in each storage vessel in the battery. The EPA is soliciting comment and suggestions for how to clarify the calculation for application by stakeholders, including how to measure throughput, the appropriate timeframe for determining the throughput, and the appropriate averaging time for determining the throughput such that the maximum potential emissions from storage vessels may be determined.

C. Definition of Certifying Official

In response to petitions on NSPS OOOO, the EPA amended the definition of 'responsible official' in order to remove potential confusion in the regulated community and to clarify that the requirements of the NSPS were not associated with a permitting program.[101] Because the terms 'responsible official' and 'permitting authority' were similar to terms used in the Title V permitting program, the EPA changed the term 'responsible official' to 'certifying official' and replaced the term 'permitting authority' used in the definition with 'Administrator.'"[102] This

[101] 79 FR 79023-4.
[102] *Id.*

amended definition of 'certifying official' was carried forward into the 2015 NSPS OOOOa proposal. 80 FR 56694. The EPA received comments that the term 'certifying official' still includes references to permitting programs and is inconsistent with way the NSPS program operates.[103] In response to this comment, the EPA stated that the change made in the 2014 amendments "remove[d] any confusion".[104] Upon further evaluation of this issue, the EPA recognizes that continuing to include the language "facilities applying for or subject to a permit" in the definition of 'certifying official' is inappropriate for the NSPS program. Therefore, the EPA is proposing to amend this definition to remove the reference to permits. The EPA solicits comment on this proposed change.

D. Equipment in VOC Service less than 300 hours/year

In this action, the EPA is proposing to amend the requirements for equipment leaks at onshore natural gas processing plants. Specifically, we are proposing to include an exemption from monitoring for certain equipment that an owner or operator designates as being in VOC service less than 300 hr/yr.

When the 2007 requirements were promulgated, the EPA concluded that an exemption for certain equipment that is in VOC service less than 300 hr/yr was appropriate. In response to public comments on the 2006 NSPS VV/VVa proposal, we stated that such exemption was appropriate for equipment that is used only during emergencies, used as a backup, or that is in service only during startup and shutdown.[105] In these situations, the operating schedule of the equipment is unpredictable and likely at widely spaced and varying intervals. Planning for monitoring is more challenging and the effort outweighs the limited potential gain in emissions.

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[103] See Docket ID No. EPA-HQ-OAR-2010-0505-6881.
[104] See Docket ID No. EPA-HQ-OAR-2010-0505-7632, Chapter 15, page 15-284.
[105] See Docket ID No. EPA-HQ-OAR-2006-0699-0094.

The EPA is proposing to include this same exemption for equipment at onshore natural gas processing plants used only during emergencies, used as a backup, or that is in service only during startup and shutdown.

E. Reporting and Recordkeeping

The EPA is proposing to streamline certain reporting and recordkeeping requirements to reduce burden on the regulated industry. The proposed changes can be seen in section 60.5420a. Additionally, the proposed reporting elements can be seen in the draft electronic reporting template, located at Docket ID No. EPA-HQ-OAR-2017-0483. We solicit comment on these proposed revisions and additional ways to streamline reporting and recordkeeping.

We are also proposing revisions to accommodate the submittal of CBI data in annual reports, as well as additional clarifications for reporting requirements during outages of the Compliance and Emissions Data Reporting Interface (CEDRI) or EPA's Central Data Exchange (CDX) systems, or during a force majeure event. These proposed changes can be seen in section 60.5420a.

F. Technical Corrections and Clarifications

We are proposing to revise the 2016 NSPS OOOOa to include the following technical corrections and clarifications.

- Revise paragraphs 60.5385a(a)(1), 60.5410a(c)(1), 60.5415a(c)(1), 60.5420a(b)(4)(i) and 60.5420a(c)(3)(i) to clarify that hours or months of operation at reciprocating compressor facilities should be measured beginning with the later of initial startup, the effective date of the requirement (August 2, 2016), or the last rod packing replacement.
- Revise paragraph 60.5393a(b)(3)(ii) to correctly cross-reference to paragraph (b)(3)(i) of that section.

- Revise paragraph 60.5397a(c)(8) to clarify the calibration requirements when Method 21 of Appendix A-7 to Part 60 is used for fugitive emission monitoring.

Commented [A17]: EPA edit to address clarification identified through implementation questions.

- Revise paragraph 60.5397a(d)(3) to correctly cross-reference paragraphs (g)(3) and (g)(4) of that section.
- Revise paragraph 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 Alaskan North Slope are not subject to any monitoring requirements.
- Revise paragraph 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. This proposed revision reflects that the 2016 NSPS OOOOa did not finalize requirements for pneumatic pumps in the gathering and boosting and transmission and storage segments. 81 FR 35850.
- Revise paragraph 60.5411a(a)(1) to remove the reference to paragraphs 60.5412a(a) and (c) for reciprocating compressor affected facilities.
- Revise paragraph 60.5411a(d)(1) to remove the reference to storage vessels, as this paragraph applies to all the sources lists in paragraph 60.5411a(d), not only storage vessels.
- Revise paragraphs 60.5412a(a)(1), 60.5412a(a)(1)(iv), 60.5412a(d)(1)(iv) and 60.5412a(d)(1)(iv)(D) to clarify that all boilers and process heaters must introduce the vent stream into the flame zone and that the performance requirement option for combustion control devices on centrifugal compressors and storage vessels is to introduce the vent stream with the primary fuel or as the primary fuel. This is the consistent with

the performance testing exemption in section 60.5413a and continuous monitoring exemption in section 60.5417a for boilers and process heaters that introduce the vent stream with the primary fuel or as the primary fuel.

- Revise paragraph 60.5412a(c) to correctly reference both paragraphs (c)(1) and (c)(2) of that section, for managing carbon in a carbon adsorption system.
- Revise paragraph 60.5413a(d)(5)(i) to reference fused silica-coated stainless steel evacuated canisters instead a specific name brand product.
- Revise paragraph 60.5413a(d)(9)(iii) to reference the total hydrocarbon span for the alternative range is on an as propane basis, just as the recommended total hydrocarbon span is on an as propane basis.
- Revise paragraph 60.5413a(d)(12) to clarify that all data elements must be submitted for each test run.
- Revise paragraph 60.5415a(b)(3) to reference all the applicable reporting and recordkeeping requirements.
- Revise paragraph 60.5416a(a)(4) to correctly cross-reference paragraph 60.5411a(a)(3)(ii).
- Revise paragraph 60.5417a(a) to clarify requirements for controls not specifically listed in paragraph (d) of that section.
- Revise paragraph 60.5422a(b) to correctly cross-reference paragraphs 60.487a(b)(1) through (3) and (b)(5).
- Revise paragraph 60.5422a(c) to correctly cross-reference paragraph 60.487a(c)(2)(i) through (iv) and (c)(2)(vii) through (viii).

- Revise paragraph 60.5423a(b) to simplify the reporting language and clarify what data is required in the report of excess emissions for sweetening unit affected facilities.
- Revise paragraph 60.5430a to remove the phrase "including but not limited to" from the "fugitive emissions component" definition. This proposed revision reflects that in the response to comments document for the 2016 NSPS OOOOa we stated we were removing this phrase.[106]
- Revise paragraph 60.5430a to remove the phrase "at the sales meter" from the "low pressure well" definition. 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 section 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 paragraphs 60.5393a(f), 60.5410a(e)(8), 60.5411a(e), 60.5415a(b), 60.5415a(b)(4), 60.5416a(d), 60.5420a(b), 60.5420a(b)(13) and introductory text in 60.5411a, 60.5416a to remove the language added in the "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Grant of Reconsideration and Partial Stay" (June 5, 2017), which was vacated by the U.S. Court of Appeals for the D.C. Circuit on July 3, 2017.

VII. Impacts of This Proposed Rule

A. What are the air impacts?

[106] See Docket ID No. EPA-HQ-OAR-2010-0505-7632, Chapter 4, page 4-319.

For this action, the EPA estimated the change in emissions that will occur due to the implementation of the proposed NSPS reconsideration for the analysis years of 2019 through 2025. We estimate impacts beginning in 2019 to reflect the year implementation of this reconsideration will begin. We estimate impacts through 2025 to illustrate the continued compound effect of this rule over a longer period. We do not estimate impacts after 2025 for reasons including limited information, as explained in the RIA (Regulatory Impact Analysis). The regulatory impact estimates for 2025 include sources newly affected in 2025 as well as the accumulation of affected sources from 2016 to 2024 that are also assumed to be in continued operation in 2025, thus incurring compliance costs and emissions reductions in 2025.

We have estimated that, over the 2019 through 2025 timeframe, the proposed NSPS reconsideration would increase methane emissions by about ~~220~~200,000 short tons, and VOC emissions by about ~~60~~56,000 tons from facilities affected by this reconsideration compared to emissions under the 2018 updated baseline, as described in the RIA. The proposed reconsideration is also expected to concurrently increase about 2,~~300~~100 tons hazardous air pollutants (HAP) from 2019 through 2025.

As described in the TSD and RIA for this rule, the EPA projected affected facilities using a combination of historical data from the United States GHG Inventory, projected activity levels taken from the Energy Information Administration (EIA's) Annual Energy Outlook (AEO), and oil and natural gas production information from DrillingInfo, a private company that provides information and analysis to the energy sector. The EPA also considered state regulations with similar requirements to the proposed NSPS in projecting affected sources for impacts analyses supporting this rule.

B. What are the energy impacts?

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

C. What are the compliance cost savings?

The EPA estimates the present value (PV) of compliance cost savings of the proposed reconsideration over 2019-2025, discounted back to 2016, will be $~~248~~234 million (in 2016 dollars) under a 7 percent discount rate, and $~~316~~299 million under a 3 percent discount rate, not including the forgone producer revenues associated with the decrease in the recovery of saleable natural gas. The equivalent annualized value (EAV) of these cost savings are $~~43~~41 million per year using a 7 percent discount rate and $~~49~~47 million per year using a 3 percent discount rate. In this analysis, we use the 2018 AEO projection of natural gas prices to estimate the value of the change in the recovered gas at the wellhead. After accounting for the change in these revenues, the estimate of the PV of compliance cost savings of the proposed reconsideration over 2019-2025, discounted back to 2016, are estimated to be $~~220~~209 million under a 7 percent discount rate, and $~~280~~265 million under a 3 percent discount rate; the corresponding estimates of the EAV of cost savings after accounting for the forgone revenues are $~~38~~36 million per year under a 7 percent discount rate, and $~~44~~41 million per year under 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 OOOOa on the United States energy system. The NEMS is a publicly-available model of the United States energy economy developed and maintained by the EIA and is used to produce the AEO, a reference publication that provides detailed forecasts of the United States energy economy.

The EPA estimated small impacts of that rule over the 2020 to 2025 period relative to the baseline for that rule. The proposed reconsideration is estimated to result in a decrease in total costs compared to the updated 2018 baseline, and the 2016 NSPS OOOOa, with the change in costs affecting a subset of the total costs estimated for the 2016 NSPS OOOOa. Therefore, the EPA expects that this deregulatory action, if finalized, would partially ameliorate the impacts estimated for the final NSPS in the 2016 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 particular concern in the current economic climate given continued interest in the employment impact of regulations such as this proposed rule.

The EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, control activities, and labor associated with new reporting and recordkeeping requirements in the 2016 NSPS OOOOa RIA. For the proposed reconsideration, EPA expects there will be slight reductions in the labor required for compliance-related activities

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associated with the 2016 NSPS OOOOa requirements relating to fugitive emissions and inspections of closed vent systems. However, due to uncertainties associated with how the proposed reconsideration will influence the portfolio of activities associated with fugitive emissions-related requirements, EPA is unable to provide quantitative estimates of compliance-related labor changes.

E. What are the forgone benefits of the proposed standards?

The EPA estimated the forgone domestic climate benefits from the methane emissions associated with this reconsideration using an interim measure of the domestic social cost of methane (SC-CH_4). The SC-CH_4 estimates used here were developed under E.O. 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. E.O. 13783 directed agencies to ensure that estimates of the social cost of greenhouse gases used in regulatory analyses "are based on the best available science and economics" and are consistent with the guidance contained in OMB Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (E.O. 13783, Section 5(c)). In addition, E.O. 13783 withdrew the technical support documents (TSDs) and the August 2016 Addendum to these TSDs describing the global social cost of greenhouse gas 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 (IWG) that included the EPA and other executive branch entities and were used in the 2016 NSPS RIA.

The forgone benefits of the proposed reconsideration are estimated in comparison to an updated baseline with the 2016 NSPS OOOOa and the March 12, 2018 amendments with respect

to the Alaskan North Slope in place. The EPA estimates the PV of the forgone domestic climate benefits over 2019-2025, discounted back to 2016, will be $7.~~7~~2 million under a 7 percent discount rate and $~~31~~28 million under a 3 percent discount rate. The EAV of these forgone benefits is $1.~~3~~2 million per year under a 7 percent discount rate and $4.~~8~~4 million per year under a 3 percent discount rate. These values represent only a partial accounting of domestic climate impacts from methane emissions, and also do not account for health effects of ozone exposure from the increase in methane emissions.

The EPA expects that the forgone VOC emission reductions may degrade air quality and adversely affect health and welfare effects associated with exposure to ozone, $PM_{2.5}$, and HAP, however data limitations prevent us from quantifying forgone VOC-related health benefits. This omission should not imply that these forgone benefits may not exist; rather, it reflects the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. As described in the RIA, with these data currently unavailable, we are unable to estimate forgone health benefits estimates for this rule due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with HAP and VOC reductions.

VIII. Statutory and Executive Order Reviews

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

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

This action is a significant regulatory action that was submitted to the OMB for review because it raises novel legal or policy issues. Any changes made in response to OMB recommendations have been documented in the docket.

In addition, the EPA prepared a Regulatory Impact Analysis (RIA) of the potential costs and benefits associated with this action. The RIA available in the docket describes in detail the empirical basis for the EPA's assumptions and characterizes the various sources of uncertainties affecting the estimates below. Table 2 shows the present value and equivalent annualized value results of the cost and benefits analysis for the proposed rule for 2019 through 2025, discounted back to 2016 using a discount rate of 7 percent. The table also shows the total increase in emissions from 2019 through 2025 from this proposed reconsideration. When discussing net benefits, we modify the relevant terminology to be more consistent with traditional net benefits analysis. In the following table, we refer to the cost savings as presented in section 2 of the RIA, and in section VII.C, above, as the "benefits" of this proposed action and the forgone benefits as presented in section 3 of the RIA, and in section VII.E, above, as the "costs" of this proposed action. The net benefits are the benefits (cost savings) minus the costs (forgone benefits).

Table 2. Summary of the Present Value and Equivalent Annualized Value of the Monetized Forgone Benefits, Cost Savings and Net Benefits of the Proposed Oil And Natural Gas Reconsideration from 2019 through 2025 (Millions of 2016$)

	Present Value	**Equivalent Annualized Value**
Benefits (Total Cost Savings)	$~~220~~209 million	$~~38~~36 million
Costs (Forgone Domestic Climate Benefits)	$7.~~7~~2 million	$1.~~3~~2 million
Net Benefits	$~~242~~201 million	$~~37~~35 million
	Non-monetized climate impacts from increases in methane emissions	

Non-monetized Forgone Benefits	Health effects of $PM_{2.5}$ and ozone exposure from an increase of ~~60~~56,000 tons of VOC from 2019 through 2025
	Health effects of HAP exposure from an increase of 2,~~300~~100 tons of HAP from 2019 through 2025
	Health effects of ozone exposure from an increase of ~~220~~200,000 short tons of methane from 2019 through 2025
	Visibility impairment
	Vegetation effects

Estimates may not sum due to independent rounding

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

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

C. Paperwork Reduction Act (PRA)

A summary of the information collection activities submitted to the Office of Management and Budget (OMB) for the final action titled, Standards of Performance for Crude Oil and Natural Gas Facilities for Construction, Modification, or Reconstruction (2016 NSPS OOOOa) under the PRA, and assigned EPA ICR Number 2523.01, can be found at 81 FR 35890. You can find a copy of the ICR in the 2016 NSPS OOOOa docket (EPA-HQ-OAR-2010-0505-7626). This proposed reconsideration revises the information collection activities of 2016 NSPS OOOOa. The revised information collection activities in this proposed rule have been submitted for approval to OMB under the PRA. The revised ICR document that the EPA prepared has been assigned EPA ICR number 2523.02. You can find a copy of the revised ICR in the docket for this rule.

The proposed changes to the 2016 NSPS OOOOa information collection activities would reduce the burden on the regulated industry associated with reporting and recordkeeping requirements. Proposed amendments to the reporting and recordkeeping requirements are

presented in section 60.5420a. Other information collection activity reductions would result from proposed amendments that streamline and align monitoring requirements (and associated recordkeeping) in the rule.

The estimated average annual burden (averaged over the first 3 years after the effective date of the standards) for the recordkeeping and reporting requirements associated with the proposed amendments to subpart OOOOa for the estimated 2,893 owners and operators subject to the rule is 156,188 labor hours, with an average annual cost of $9,615,691 (2016$) over the three-year period. The information collection activities associated with the proposed amendments would result in an estimated average annual burden reduction of 8 percent compared to the previously-submitted 2016 NSPS OOOOa ICR (2016$).

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.

Submit your comments on the Agency's need for this information, the accuracy of the provided revised burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to RIA_submissions@omb.eop.gov, Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than **[INSERT DATE 30 DAYS AFTER PUBLICATION IN THE FEDERAL REGISTER]**. The EPA will respond to any ICR-related comments in the 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 proposed rule, including small entities, is reduced compared to the 2016 NSPS 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 of 1995 (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. 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 it is not economically significant as defined in Executive Order 12866. The 2016 NSPS OOOOa, as discussed in the RIA,[107] was anticipated to reduce emissions of methane, VOC, and HAPs, and some of the benefits of reducing these pollutants would have accrued to children. However, new data and analysis have affected expectations about how extensive the impact of the fugitive emissions program in the 2016 NSPS OOOOa would have on these benefits. Furthermore, while the proposed amendment is expected to decrease the impact of the fugitive emissions program in the 2016 NSPS OOOOa on these benefits, as discussed in Chapter 1 of the RIA, the potential decrease in emission reduction (and thus the benefit) from the proposed amendment is minimal compared to the overall emission reduction that would continue to be achieved under the amended 40 CFR part 60, subpart OOOOa.

Moreover, the proposed 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 proposed 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. For the reasons stated above, we do not believe this small decrease in emission reduction from this action will have a disproportionate adverse effect on children's health.

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[107] See Chapter 4, "Economic Impact Analysis and Distributional Assessments", of the RIA.

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. The basis for this determination can be found in the 2016 NSPS OOOOa (81 FR 35894).

J. National Technology Transfer and Advancement Act (NTTAA)

This action involves technical standards.[108] 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 were identified for EPA Methods 1A, 2A, 2D, 21, and 22 and none were brought to its attention in comments. All potential standards were reviewed to determine the practicality of the voluntary consensus standards (VCS) for this rule.

Two VCS were identified as an acceptable alternative to EPA test methods for the purpose of this rule. First, ANSI/ASME PTC 19-10–1981, Flue and Exhaust Gas Analyses (Part 10) was identified to be used in lieu of EPA Methods 3B, 6, 6A, 6B, 15A and 16A manual portions only and not the instrumental portion. This standard includes manual and instructional methods of analysis for carbon dioxide, carbon monoxide, hydrogen sulfide, nitrogen oxides, oxygen, and sulfur dioxide. Second, ASTM D6420-99 (2010), "Test Method for Determination

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

of Gaseous Organic Compounds by Direct Interface Gas Chromatography/Mass Spectrometry" is an acceptable alternative to EPA Method 18 with the following caveats, only use when the target compounds are all known and the target compounds are all listed in ASTM D6420 as measurable. ASTM D6420 should never be specified as a total VOC Method. (ASTM D6420-99 (2010) is not incorporated by reference in 40 CFR part 60.) The search identified 19 VCS that were potentially applicable for this rule in lieu of EPA reference methods. However, these have been determined to not be practical due to lack of equivalency, documentation, validation of data and other important technical and policy considerations. For additional information, please see the 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 proposed action is unlikely to 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). The 2016 NSPS OOOOa was anticipated to reduce emissions of methane, VOC, and HAPs, and some of the benefits of reducing these pollutants would have accrued to minority populations, low-income populations and/or indigenous peoples. However, new data and analysis have affected expectations about how extensive the impact of the fugitive emissions program in the 2016 NSPS OOOOa would have on these benefits. Furthermore, while these communities may experience forgone benefits as a result of this action, as discussed in Chapter 1 of the RIA, the potential foregone emission reductions (and related benefits) from the proposed

amendments is minimal compared to the overall emission reductions (and related benefits) from the 2016 NSPS.

Moreover, the proposed 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 proposed 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

For the reasons stated above, the EPA believes that this proposed action is unlikely to have disproportionately high and adverse human health or environmental effects on minority populations, low-income populations and/or indigenous peoples. We note that the potential impacts of this proposed action are not expected to be experienced uniformly, and the distribution of avoided compliance costs associated with this action depends on the degree to which costs would have been passed through to consumers.

Commented [A20]: Updated per OMB 5/10 comment

List of Subjects in 40 CFR Part 60

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

Dated: _____.

E. Scott Pruitt,

Administrator.

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

PART 60-- STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015

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§60.5360a What is the purpose of this subpart?

§60.5365a Am I subject to this subpart?

§60.5370a When must I comply with this subpart?

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

§60.5380a What GHG and VOC standards apply to centrifugal compressor affected facilities?

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

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

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

§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?

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

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

§60.5402a What are the alternative means of emission limitations for GHG and VOC equipment leaks from onshore natural gas processing plants?

§60.5405a What standards apply to sweetening unit affected facilities at onshore natural gas processing plants?

§60.5406a What test methods and procedures must I use for my sweetening unit affected facilities at onshore natural gas processing plants?

§60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

§60.5408a What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

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

§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?

§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?

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

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

§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?

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

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

§60.5421a What are my additional recordkeeping requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

§60.5422a What are my additional reporting requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

§60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

§60.5425a What parts of the General Provisions apply to me?

§60.5430a What definitions apply to this subpart?

§60.5432a How do I determine whether a well is a low pressure well using the low pressure well equation?

§§60.5433a-60.5499a [Reserved]

Table 1 to Subpart OOOOa of Part 60—Required Minimum Initial SO_2 Emission Reduction Efficiency (Z_i)

Table 2 to Subpart OOOOa of Part 60—Required Minimum SO_2 Emission Reduction Efficiency (Z_c)

Table 3 to Subpart OOOOa of Part 60—Applicability of General Provisions to Subpart OOOOa

§60.5360a What is the purpose of this subpart?

(a) This subpart establishes emission standards and compliance schedules for the control of the pollutant greenhouse gases (GHG). The greenhouse gas standard in this subpart is in the form of a limitation on emissions of methane from affected facilities in the crude oil and natural gas source category that commence construction, modification, or reconstruction after September 18, 2015. This subpart also establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities in the crude oil and natural gas source category that commence construction, modification or reconstruction after September 18, 2015. The effective date of the rule is August 2, 2016.

(b) *Prevention of Significant Deterioration (PSD) and title V thresholds for Greenhouse Gases.* (1) For the purposes of 40 CFR 51.166(b)(49)(ii), with respect to GHG emissions from

affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Act as defined in 40 CFR 51.166(b)(48) and in any State Implementation Plan (SIP) approved by the EPA that is interpreted to incorporate, or specifically incorporates, §51.166(b)(48).

(2) For the purposes of 40 CFR 52.21(b)(50)(ii), with respect to GHG emissions from affected facilities, the "pollutant that is subject to the standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is subject to regulation under the Clean Air Act as defined in 40 CFR 52.21(b)(49).

(3) For the purposes of 40 CFR 70.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 70.2.

(4) For the purposes of 40 CFR 71.2, with respect to greenhouse gas emissions from affected facilities, the "pollutant that is subject to any standard promulgated under section 111 of the Act" shall be considered to be the pollutant that otherwise is "subject to regulation" as defined in 40 CFR 71.2.

§60.5365a Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section for which you commence construction, modification, or reconstruction after September 18, 2015.

(a) Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing. The provisions of this paragraph do not

affect the affected facility status of well sites for the purposes of §60.5397a. The provisions of paragraphs (a)(1) through (4) of this section apply to wells that are hydraulically refractured:

(1) A well that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of §60.5375a(a)(1) through (4) are met. However, hydraulic refracturing of a well constitutes a modification of the well site for purposes of paragraph (i)(3)(iii) of this section, regardless of affected facility status of the well itself.

(2) A well completion operation following hydraulic refracturing not conducted pursuant to §60.5375a(a)(1) through (4) is a modification to the well.

(3) Except as provided in §60.5365a(i)(3)(iii), refracturing of a well, by itself, does not affect the modification status of other equipment, process units, storage vessels, compressors, pneumatic pumps, or pneumatic controllers.

(4) A well initially constructed after September 18, 2015, that conducts a well completion operation following hydraulic refracturing is considered an affected facility regardless of this provision.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(d) Each pneumatic controller affected facility:

(1) Each pneumatic controller affected facility not located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

(2) Each pneumatic controller affected facility located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller.

(e) Each storage vessel affected facility, which is a single storage vessel with the potential for VOC emissions equal to or greater than 6 tpy as determined according to this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this subsection. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a federal, state, local or tribal authority.

(1) For each new, modified or reconstructed storage vessel you must determine the potential for VOC emissions within 30 days after liquids first enter the storage vessel, except as provided in paragraph (e)(3)(iv) of this section. For each new, modified or reconstructed storage vessel receiving liquids pursuant to the standards for well affected facilities in §60.5375a, including wells subject to §60.5375a(f), you must determine the potential for VOC emissions within 30 days after startup of production of the well.

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

(3) For storage vessels not subject to a legally and practically enforceable limit in an operating permit or other requirement established under federal, state, local or tribal authority,

any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(3)(i) through (iv) of this section.

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

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

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

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

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

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

(f) The group of all equipment within a process unit is an affected facility. (1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by §§60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of §§60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG, or GGGa of this part.

(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in §60.5423a(c) but are not required to comply with §§60.5405a through 60.5407a and §§60.5410a(g) and 60.5415a(g).

(4) Sweetening facilities producing acid gas that is completely re-injected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§60.5405a through 60.5407a, 60.5410a(g), 60.5415a(g), and 60.5423a.

(h) Each pneumatic pump affected facility:

(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump.

(2) For well sites, each pneumatic pump affected facility, which is a single natural gas-driven diaphragm pump. A single natural gas-driven diaphragm pump that is in operation less than 90 days per calendar year is not an affected facility under this subpart provided the owner/operator keeps records of the days of operation each calendar year and submits such records to the EPA Administrator (or delegated enforcement authority) upon request. For the purposes of this section, any period of operation during a calendar day counts toward the 90 calendar day threshold.

(i) Except as provided in §60.5365a(i)(2), the collection of fugitive emissions components at a well site, as defined in §60.5430a, is an affected facility.

(1) [Reserved]

(2) A well site that only contains one or more wellheads is not an affected facility under this subpart. The affected facility status of a separate tank battery surface site has no effect on the affected facility status of a well site that only contains one or more wellheads.

(3) For purposes of §60.5397a, a "modification" to a well site occurs when:

(i) A new well is drilled at an existing well site;

(ii) A well at an existing well site is hydraulically fractured; or

(iii) A well at an existing well site is hydraulically refractured.

(4) For purposes of §60.5397a, a "modification" to a separate tank battery occurs when:

(i) Any of the actions in paragraphs §60.5365a(i)(3)(i) through (iii) occurs at an existing separate tank battery;

(ii) A well sending production to an existing separate tank battery is modified, as defined in §60.5365a(i)(3)(i) through (iii); 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 separate tank battery.

(j) The collection of fugitive emissions components at a compressor station, as defined in §60.5430a, is an affected facility. For purposes of §60.5397a, a "modification" to a compressor station occurs when:

(1) An additional compressor is installed at a compressor station; or

(2) One or more compressors at a compressor station is replaced by one or more compressors of greater total horsepower than the compressor(s) being replaced. When one or more compressors is replaced by one or more compressors of an equal or smaller total horsepower than the compressor(s) being replaced, installation of the replacement compressor(s) does not trigger a modification of the compressor station for purposes of §60.5397a.

§60.5370a When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than August 2, 2016 or upon startup, whichever is later.

(b) At all times, including periods of startup, shutdown, and malfunction, owners and operators shall maintain and operate any affected facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the Administrator which may include, but is not limited to, monitoring results, opacity observations, review of operating and maintenance procedures, and inspection of the source. The provisions for exemption from compliance during

periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

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

If you are the owner or operator of a well affected facility as described in §60.5365a(a) that also meets the criteria for a well affected facility in §60.5365(a) of subpart OOOO of this part, you must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with paragraphs (a) through (g) of this section. If you own or operate a well affected facility as described in §60.5365a(a) that does not meet the criteria for a well affected facility in §60.5365(a) of subpart OOOO of this part, you must reduce GHG and VOC emissions by complying with paragraphs (f)(3), (f)(4) or (g) for each well completion operation with hydraulic fracturing prior to November 30, 2016, and you must comply with paragraphs (a) through (g) of this section for each well completion operation with hydraulic fracturing on or after November 30, 2016.

(a) Except as provided in paragraph (f) and (g) of this section, for each well completion operation with hydraulic fracturing you must comply with the requirements in paragraphs (a)(1) through (4) of this section. You must maintain a log as specified in paragraph (b) of this section.

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

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

(ii) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the recovered liquids into the well or another well, or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an onsite fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is technically infeasible to route the recovered gas as required above, follow the requirements in paragraph (a)(3) of this section. If, at any time during the separation flowback stage, it is technically infeasible for a separator to function, you must comply with paragraph (a)(1)(i) of this section.

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

(A) A well that is not hydraulically fractured or refractured with liquids, or that does not generate condensate, intermediate hydrocarbon liquids, or produced water such that there is no liquid collection system at the well site is not required to have a separator onsite.

(B) If conditions allow for liquid collection, then the operator must immediately stop the well completion operation, install a separator, and restart the well completion operation in accordance with §60.5375a(a)(1).

(C) The owner or operator of a well that meets the criteria of paragraph (a)(1)(iii)(A) or (B) of this section must submit the report in §60.5420a(b)(2) and maintain the records in §60.5420a(c)(1)(iii).

(2) [Reserved]

(3) If it is technically infeasible to route the recovered gas as required in §60.5375a(a)(1)(ii), then you must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

(4) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

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

(c) You must demonstrate initial compliance with the standards that apply to well affected facilities as required by §60.5410a(a).

(d) You must demonstrate continuous compliance with the standards that apply to well affected facilities as required by §60.5415a(a).

(e) You must perform the required notification, recordkeeping and reporting as required by §60.5420a(a)(2), (b)(1) and (2), and (c)(1).

(f) For each well affected facility specified in paragraphs (f)(1) and (2) of this section, you must comply with the requirements of paragraphs (f)(3) and (4) of this section.

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

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

(3) You must comply with either paragraph (f)(3)(i) or (f)(3)(ii) of this section, unless you meet the requirements in paragraph (g) of this section. You must also comply with paragraph (b) of this section.

(i) Route all flowback to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.

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

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

(g) For each well affected facility with less than 300 scf of gas per stock tank barrel of oil produced, you must comply with paragraphs (g)(1) and (2) of this section.

(1) You must maintain records specified in §60.5420a(c)(1)(vi).

(2) You must submit reports specified in §60.5420a(b)(1) and (2).

§60.5380a What GHG and VOC standards apply to centrifugal compressor affected facilities?

You must comply with the GHG and VOC standards in paragraphs (a) through (d) of this section for each centrifugal compressor affected facility.

(a)(1) You must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411a(b). The cover must be connected through a closed vent system that meets the requirements of §60.5411a(a) and (d) and the closed vent system must be routed to a control device that meets the conditions specified in §60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

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

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

(d) You must perform the reporting as required by §60.5420a(b)(1) and (3), and the recordkeeping as required by §60.5420a(c)(2), (6) through (11), and (17), as applicable.

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

You must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

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

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

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

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

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

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

(d) You must perform the reporting as required by §60.5420a(b)(1) and (4) and the recordkeeping as required by §60.5420a(c)(3), (6) through (9), and (17), as applicable.

§60.5390a What GHG and VOC standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the GHG and VOC standards, based on natural gas as a surrogate for GHG and VOC, in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from this requirement.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety and positive actuation. However, you must tag such pneumatic controller with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in §60.5420a(c)(4)(ii).

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification

information that allows traceability to the records for that pneumatic controller as required in §60.5420a(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in §60.5420a(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by §60.5410a(d).

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by §60.5415a(d).

(f) You must perform the reporting as required by §60.5420a(b)(1) and (5) and the recordkeeping as required by §60.5420a(c)(4).

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

For each pneumatic pump affected facility you must comply with the GHG and VOC standards, based on natural gas as a surrogate for GHG and VOC, in either paragraph (a) or (b) of this section, as applicable, on or after November 30, 2016.

(a) Each pneumatic pump affected facility at a natural gas processing plant must have a natural gas emission rate of zero.

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

(1) [Reserved]

(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.

(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)(2) of this section within 30 days of startup of the control device or within 30 days of the ability to route to a process.

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

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

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

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

(iii) The assessment of technical feasibility to route emissions from the pneumatic pump to an existing control device onsite or to a process shall include, but is not limited to, safety considerations, distance from the control device, pressure losses and differentials in the closed vent system and the ability of the control device to handle the pneumatic pump emissions which are routed to them. The assessment of technical infeasibility shall be prepared under the direction or supervision of the in-house engineer or qualified professional engineer who signs the certification in accordance with paragraph (b)(2)(ii) of this section.

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

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

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

(d) You must demonstrate initial compliance with standards that apply to pneumatic pump affected facilities as required by §60.5410a(e).

(e) You must perform the reporting as required by §60.5420a(b)(1) and (8) and the recordkeeping as required by §60.5420a(c)(6) through (10), (16), and (17), as applicable.

(f) [Reserved]

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

EFFECTIVE DATE NOTE: At 82 FR 25733, June 5, 2017, in §60.5393a, paragraphs (b) and (c) were stayed until Aug. 31, 2017.

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

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

(a) You must comply with the requirements of paragraphs (a)(1) and (2) of this section. After 12 consecutive months of compliance with paragraph (a)(2) of this section, you may continue to comply with paragraph (a)(2) of this section, or you may comply with paragraph (a)(3) of this section, if applicable. If you choose to meet the requirements in paragraph (a)(3) of

this section, you are not required to comply with the requirements of paragraph (a)(2) of this section except as provided in paragraphs (a)(3)(i) and (ii) of this section.

(1) Determine the potential for VOC emissions in accordance with §60.5365a(e).

(2) Reduce VOC emissions by 95.0 percent within 60 days after startup. For storage vessel affected facilities receiving liquids pursuant to the standards for well affected facilities in §60.5375a(a)(1)(i) or (ii), you must achieve the required emissions reductions within 60 days after startup of production as defined in §60.5430a.

(3) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology, and the calculations must be based on the average throughput for the month. You may no longer comply with this paragraph and must instead comply with paragraph (a)(2) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (a)(3)(i) or (ii) of this section.

(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (a)(2) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.

(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected

facility, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination.

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

(2) If you use a floating roof to reduce emissions, you must meet the requirements of §60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

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

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

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

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

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

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

(d) Compliance, notification, recordkeeping, and reporting. You must comply with paragraphs (d)(1) through (3) of this section.

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

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

(3) You must perform the required reporting as required by §60.5420a(b)(1) and (6) and the recordkeeping as required by §60.5420a(c)(5) through (8), (12) through (14), and (17), as applicable.

(e) Exemptions. This subpart does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, and 40 CFR part 63, subparts G, CC, HH, or WW.

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

For each affected facility under §60.5365a(i) and (j), you must reduce GHG (in the form of a limitation on emissions of methane) and VOC emissions by complying with the requirements of paragraphs (a) through (j) of this section. These requirements are independent of the closed vent system and cover requirements in §60.5411a.

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

(b) You must develop an emissions monitoring plan that covers the collection of fugitive emissions components at well sites and compressor stations within each company-defined area in accordance with paragraphs (c) and (d) of this section.

(c) Fugitive emissions monitoring plans must include the elements specified in paragraphs (c)(1) through (8) of this section, at a minimum.

(1) Frequency for conducting surveys. Surveys must be conducted at least as frequently as required by paragraphs (f) and (g) of this section.

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

(3) Manufacturer and model number of fugitive emissions detection equipment to be used.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (h) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) If you are using optical gas imaging, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

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

(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60g/hr from a quarter inch diameter orifice.

(ii) Procedure for a daily verification check.

(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(v) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (e.g., steam).

(vi) Training and experience needed prior to performing surveys.

(vii) Procedures for calibration and maintenance. At a minimum, procedures must comply with those recommended by the manufacturer.

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

(i) Verification that your monitoring equipment meets the requirements specified in Section 6.0 of Method 21 at 40 CFR part 60, appendix A-7. For purposes of instrument capability, the fugitive emissions definition shall be 500 ppm or greater methane using a FID-based instrument. If you wish to use an analyzer other than a FID-based instrument, you must develop a site-specific fugitive emission definition that would be equivalent to 500 ppm methane using a FID-based instrument (e.g., 10.6 eV PID with a specified isobutylene concentration as the fugitive emission definition would provide equivalent response to your compound of interest).

(ii) Procedures for conducting surveys. At a minimum, the procedures shall ensure that the surveys comply with the relevant sections of Method 21 at 40 CFR part 60, appendix A-7, including Section 8.3.1.

(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 calibration 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 these readings by the initial calibration values 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 OGI, your plan must include a sitemap or plot plan and the information in paragraph (d)(1)(i) or (ii) through (iv):

(i) A defined observation path that ensures that all fugitive emissions components are within sight of the path. The observation path must account for interferences.

(ii) For closed vent systems regulated under this section, a narrative description of how the closed vent system will be monitored, including a description and the location of all fugitive emissions components located on the closed vent system. The sitemap or plot plan must include the location of each closed vent system.

(iii) For controlled storage vessels regulated under this section, a narrative description of how the storage vessel will be monitored including a description and location of all fugitive emissions components located on the controlled storage vessel. The sitemap or plot plan must include the location of each controlled storage vessel.

(iv) For all other fugitive emissions components not associated with a closed vent system or controlled storage vessel regulated under this section, a narrative description of how the fugitive emissions components will be monitored, including a description and location of all fugitive emissions components. The description and location of fugitive emissions components may be grouped by unit operations (*e.g.,* separator, heater/treater, glycol dehydrator). The sitemap or plot plan must include the location of each unit operation.

(2) If you are using Method 21, your plan must include a list of fugitive emissions components to be monitored and method for determining location of fugitive emissions components to be monitored in the field (*e.g.* tagging, identification on a process and instrumentation diagram, etc.). If you are using OGI, you may comply with this requirement in lieu of paragraph (d)(1) of this section.

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

(e) Each monitoring survey shall observe each fugitive emissions component, as defined in §60.5430a, for fugitive emissions.

(f)(1) You must conduct an initial monitoring survey within 60 days of the startup of production, as defined in §60.5430a, for each collection of fugitive emissions components at a new well site or by June 3, 2017, whichever is later. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 60 days of the first day of production for each collection of fugitive emission components after the modification or by June 3, 2017, whichever is later. 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 later.

(2) You must conduct an initial monitoring survey within 60 days of the startup of a new compressor station for each new collection of fugitive emissions components at the new compressor station or by June 3, 2017, whichever is later. For a modified collection of fugitive components at a compressor station, the initial monitoring survey must be conducted within 60 days of the modification or by June 3, 2017, whichever is later. 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 later.

(g) A monitoring survey of each collection of fugitive emissions components at a well site or at a compressor station must be performed at the frequencies specified in paragraphs (g)(1) and (2) of this section, with the exceptions noted in paragraphs (g)(3), (4), and (6) of this section.

(1) A monitoring survey of each collection of fugitive emissions components at a well site within a company-defined area must be conducted at the frequencies specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) At least semiannually for the 2-year period following the initial survey, then at least annually. Consecutive semiannual monitoring surveys must be conducted at least 4 months apart. Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

(ii) At least annually for each collection of fugitive emissions components located at one of the types of well sites in paragraphs (g)(1)(ii)(A) through (B). Consecutive annual monitoring surveys must be conducted at least 9 months apart and no more than 13 months apart.

(A) A well site located on the Alaskan North Slope; or

(B) A well site with average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production, where boe equals cubic feet gas/5658.53.

(2) Except as provided herein, a monitoring survey of the collection of fugitive emissions components at a compressor station within a company-defined area must be conducted at least quarterly after the initial survey. Consecutive quarterly monitoring surveys must be conducted at least 60 days apart. Each compressor must be monitored while in operation (*i.e.*, not in stand-by mode) at least annually. 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.

(3) Fugitive emissions components that cannot be monitored without elevating the monitoring personnel more than 2 meters above the surface may be designated as difficult-to-monitor. Fugitive emissions components that are designated difficult-to-monitor must meet the specifications of paragraphs (g)(3)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated difficult-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as difficult-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as difficult-to-monitor is difficult-to-monitor.

(iv) The plan must include a schedule for monitoring the difficult-to-monitor fugitive emissions components at least once per calendar year.

(4) Fugitive emissions components that cannot be monitored because monitoring personnel would be exposed to immediate danger while conducting a monitoring survey may be designated as unsafe-to-monitor. Fugitive emissions components that are designated unsafe-to-monitor must meet the specifications of paragraphs (g)(4)(i) through (iv) of this section.

(i) A written plan must be developed for all of the fugitive emissions components designated unsafe-to-monitor. This written plan must be incorporated into the fugitive emissions monitoring plan required by paragraphs (b), (c), and (d) of this section.

(ii) The plan must include the identification and location of each fugitive emissions component designated as unsafe-to-monitor.

(iii) The plan must include an explanation of why each fugitive emissions component designated as unsafe-to-monitor is unsafe-to-monitor.

(iv) The plan must include a schedule for monitoring the fugitive emissions components designated as unsafe-to-monitor.

(5) The requirements of paragraph (g)(2) of this section are waived for any collection of fugitive emissions components at a compressor station located within an area that has an average calendar month temperature below 0° Fahrenheit for two of three consecutive calendar months of a quarterly monitoring period. The calendar month temperature average for each month within the quarterly monitoring period must be determined using historical monthly average temperatures over the previous three years as reported by a National Oceanic and Atmospheric Administration source or other source approved by the Administrator. The requirements of

paragraph (g)(2) of this section shall not be waived for two consecutive quarterly monitoring periods.

(6) 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) Each identified source of fugitive emissions shall be repaired as soon as practicable, but no later than 60 calendar days after detection of the fugitive emissions.

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

(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, well shutdown, well shut-in, after a scheduled vent blowdown or within 2 years, whichever is earlier. For purposes of this requirement, 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 repaired fugitive emissions component must be resurveyed 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 repaired fugitive emissions components using either Method 21 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, must clearly identify the component by location within the site (e.g., the latitude and longitude of the component or by other descriptive landmarks visible in the picture).

(iii) Operators that use Method 21 to resurvey the repaired fugitive emissions components are subject to the resurvey provisions specified in paragraphs (h)(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 are used.

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

(iv) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (h)(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.

(i) Records for each monitoring survey shall be maintained as specified §60.5420a(c)(15).

(j) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that include the information specified in §60.5420a(b)(7). Multiple collection of fugitive emissions components at a well site or at a compressor station may be included in a single annual report.

EFFECTIVE DATE NOTE: At 82 FR 25733, June 5, 2017, §60.5397a was stayed until Aug. 31, 2017.[81 FR 35898, June 3, 2016, as amended at 83 FR 10638, Mar. 12, 2018]

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

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in GHG (in the form of a limitation on emission of methane) and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under §60.5375a, §60.5385a, and §60.5397a, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with §60.5375a, §60.5385a, and §60.5397a. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

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

(c) The Administrator will consider applications under this section from owners or operators of affected facilities, and manufacturers or vendors of leak detection technologies, or trade associations provided they are submitted in conjunction with an owner or operator.

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

(1) The applicant must provide information that is sufficient for demonstrating the equivalence of the alternative means of emission limitation. At a minimum, the applicant must collect, verify, and submit field data to demonstrate the equivalence of the alternative means of emission limitation; the field data must encompass seasonal variations over the year to ensure that the technique works appropriately in different conditions that will be encountered during monitoring surveys. The field data may be supplemented with modeling analyses, test data, or other documentation. The application must include the following information:

(i) A description of the technology, technique, or process.

(ii) A description of the monitoring instrument or measurement technology used in the technology, technique, or process.

(iii) A description of performance based procedures (i.e., method) and data quality indicators for precision and bias; the method detection limit of the technology, technique, or process.

(iv) For affected facilities under §60.5397a, the action criteria and level at which a fugitive emission exists.

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

(vi) Timeframes for conducting ongoing quality assurance/quality control.

(vii) Field data verifying viability and detection capabilities of the technology, technique, or process. Test data, modeling analyses, or other documentation may be used to supplement field data.

(viii) Frequency of measurements and surveys conducted with the technology, technique, or process.

(ix) For continuous monitoring techniques, the minimum data availability.

(x) Sufficient data and other supporting documentation for determining the emissions reductions achieved or avoided by the technology, technique, or process.

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

(xii) Operation and maintenance procedures and other provisions necessary to ensure reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under §60.5397a.

(xiii) Initial and continuous compliance procedures, including recordkeeping and reporting, if the compliance procedures are different than those specified in §60.5397a(d).

(2) For each determination of equivalency requested, the emission reduction achieved by the design, equipment, work practice or operational requirements shall be demonstrated by field data, which can be supplemented with modeling analyses at an active production site or test data at a controlled test environment or facility.

(3) For each technology, technique, or process for which a determination of equivalency is requested, the emission reduction achieved by the alternative means of emission limitation shall be demonstrated.

(e) After notice and opportunity for public hearing, the Administrator will determine the equivalence of a means of emission limitation and will publish the determination in the FEDERAL REGISTER.

(f)(1) An application submitted under this section will be evaluated based on the field data, modeling analyses, and other documentation that was provided to demonstrate the equivalence of the alternative means of emission limitation under this section.

(2) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure that equivalent emission reductions are achieved.

(2) The Administrator may condition the approval of the alternative means of emission limitation on requirements that may be necessary to ensure that sufficient emission reductions are achieved for satisfying the requirement for equivalency.

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

§60.5399a 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 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 (g) through (m) 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.

(a) The Administrator will consider applications for alternative fugitive emissions standards based on equivalent state, local, or tribal program under this section from any interested person, which includes, but is not limited to individuals, corporations, partnerships, associations, state, or municipalities.

(b) 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.

(c) After notice and opportunity for public comment, the Administrator will determine the equivalence of an alternative fugitive emissions standard and will publish the determination in the **Federal Register**.

(d)(1) An application submitted under this section will be evaluated based on the documentation that was provided to demonstrate the equivalence of the alternative fugitive emissions standards under this section.

(2) The Administrator may condition the approval of the alternative fugitive emissions standards on requirements that may be necessary to ensure that equivalent emissions reductions are achieved.

(e) 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) may be used by any owner or operator in meeting the relevant standards and requirements established for affected facilities under §60.5397a.

(f)(1) An owner or operator must notify the Administrator before implementing one of the alternative fugitive emissions standards, as specified in §60.5420a(a)(3).

(2) An owner or operator implementing one of the alternative fugitive emissions standards must include the information specified in §60.5420a(b)(7) in the annual report and maintain the records specified by the specific alternative fugitive emissions standard for a period of at least 5 years.

(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 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 and GHG emissions through compliance with the monitoring, repair, and recordkeeping requirements in the California Code of Regulations, title 17, §§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) of this subpart.

(h) *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, §§XII.L, effective June 30, 2018, or XVII.F, effective October 15, 2014 for well sites and January 1, 2015 for compressor stations, as an alternative to complying with the requirements in §60.5397a(f)(1) and (2), (g)(1) through (4), (h), and (i) of this subpart, provided the monitoring instrument used is OGI or a Method 21 instrument.

(i) *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) of this subpart, provided the leak definition used is Method 21 monitoring with an instrument reading of 500 ppm or greater.

(j) *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)

of this subpart, provided the leak definition used is Method 21 monitoring with an instrument reading of 500 ppm or greater.

(k) *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) of this subpart, provided the monitoring instrument used is OGI or a Method 21 instrument.

(l) *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 ~~H~~G, effective ~~January 16, 2015~~August 8, 2018, as an alternative to complying with the requirements in §60.5397a(f)(2), (g)(2) through (4), (h), and (i) of this subpart, provided the monitoring instrument used is OGI or a Method 21 instrument.

(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 Tex. Admin. Code §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) of this subpart, provided the monitoring instrument used is a Method 21 instrument and that the leak definition used for Method 21 monitoring is an instrument reading of 2,000 ppm or greater.

(m) *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) of this subpart.

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

This section applies to the group of all equipment, except compressors, within a process unit.

(a) You must comply with the requirements of §§60.482-1a(a), (b), (d), and (e), 60.482-2a, and 60.482-4a through 60.482-11a, except as provided in §60.5401a.

(b) You may elect to comply with the requirements of §§60.483-1a and 60.483-2a, as an alternative.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least

equivalent to that achieved by the controls required in this subpart according to the requirements of §60.5402a.

(d) You must comply with the provisions of §60.485a except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§60.486a and 60.487a except as provided in §§60.5401a, 60.5421a, and 60.5422a.

(f) You must use the following provision instead of §60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169-93, E168-92, or E260-96 (incorporated by reference as specified in §60.17) must be used.

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

(a) You may comply with the following exceptions to the provisions of §60.5400a(a) and (b).

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in §60.485a(b)

except as provided in §60.5400a(c) and in paragraph (b)(4) of this section, and §60.482-4a(a) through (c) of subpart VVa of this part.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in §60.482-9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are onsite, instead of within 5 days as specified in paragraph (b)(1) of this section and §60.482-4a(b)(1).

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section may be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of §60.482-5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§60.482-2a(a)(1), 60.482-7a(a), 60.482-11a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the monitoring

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

(f) An owner or operator may use the following provisions instead of §60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °Celsius (302 °Fahrenheit) as determined by ASTM Method D86-96 (incorporated by reference as specified in §60.17).

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

definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

§60.5402a What are the alternative means of emission limitations for GHG and VOC equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in GHG and VOC emissions at least equivalent to the reduction in GHG and VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the FEDERAL REGISTER, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

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

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) An application submitted under paragraph (c) of this section must meet the following criteria:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) The application must include operation, maintenance and other provisions necessary to assure reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under the design, equipment, work practice or operational standard in paragraph (a) of this section by including the information specified in paragraphs (d)(1)(i) through (x) of this section.

(i) A description of the technology or process.

(ii) The monitoring instrument and measurement technology or process.

(iii) A description of performance based procedures (i.e. method) and data quality indicators for precision and bias; the method detection limit of the technology or process.

(iv) The action criteria and level at which a fugitive emission exists.

(v) Any initial and ongoing quality assurance/quality control measures.

(vi) Timeframes for conducting ongoing quality assurance/quality control.

(vii) Field data verifying viability and detection capabilities of the technology or process.

(viii) Frequency of measurements.

(ix) Minimum data availability.

(x) Any restrictions for using the technology or process.

(3) The application must include initial and continuous compliance procedures including recordkeeping and reporting.

§60.5405a What standards apply to sweetening unit affected facilities at onshore natural gas processing plants?

(a) During the initial performance test required by §60.8(b), you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

§60.5406a What test methods and procedures must I use for my sweetening unit affected facilities at onshore natural gas processing plants?

(a) In conducting the performance tests required in §60.8, you must use the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in §60.8(b).

(b) During a performance test required by §60.8, you must determine the minimum required reduction efficiencies (Z) of SO_2 emissions as required in §60.5405a(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$X = KQ_aY$

Where:

X = average sulfur feed rate, Mg/D (LT/D).

Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).

Y = average H_2S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.

K = (32 kg S/kg-mole)/((24.04 dscm/kg-mole)(1000 kg S/Mg)).

= 1.331×10^{-3}Mg/dscm, for metric units.

= (32 lb S/lb-mole)/((385.36 dscf/lb-mole)(2240 lb S/long ton)).

= 3.707×10^{-5} long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in §60.5408a or a chromatographic procedure following ASTM E260-96 (incorporated by reference as specified in §60.17) to determine the

H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine compliance with the SO_2 standards in §60.5405a(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$R = (100S)/(S + E)$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage vessels. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$E = C_e Q_{sd}/K_1$

Where:

E = emission rate of sulfur per run, kg/hr.

C_e = concentration of sulfur equivalent (SO^{2+} reduced sulfur), g/dscm (lb/dscf).

Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).

K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2 and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of appendix A-1 of this part to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m^2 or more, and the centroid is more than 1 m (39 in) from the wall.

(i) You must use Method 6 of appendix A-4 of this part to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent. In place of Method 6 of Appendix A of this part, you may use ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17).

(ii) You must use Method 15 of appendix A-5 of this part to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft^3/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A of appendix A-6 of this part or Method 15 of appendix A-5 of this part or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by

reference as specified in §60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A-1 of this part to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

§60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

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

(1) The accumulation of sulfur product over each 24-hour period. The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels

with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ±2 percent of the 24-hour sulfur accumulation.

(2) The H_2S concentration in the acid gas from the sweetening unit for each 24-hour period. At least one sample per 24-hour period must be collected and analyzed using the equation specified in §60.5406a(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is within ±20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ±20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) The average acid gas flow rate from the sweetening unit. You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) The sulfur feed rate (X). For each 24-hour period, you must compute X using the equation specified in §60.5406a(b)(1).

(5) The required sulfur dioxide emission reduction efficiency for the 24-hour period. You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of §60.5405a(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere. The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405a(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with §60.5405a(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ±1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of §60.8 to demonstrate compliance with the standards under §60.5405a, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate

level determined during the most recent performance test to ensure the sulfur compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under §60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of §60.5405a(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock

interval. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in §60.5406a(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

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Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

K_2 = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by §60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of §60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by §60.13(c), Performance Specification 2 of appendix B of this part must apply, and Method 6 of appendix A-4 of this part must be used for systems required by paragraph (b) of this section. In place of Method 6 of appendix A-4 of this part, ASME PTC 19.10-1981 (incorporated by reference—see §60.17) may be used.

§60.5408a What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A-80-20-A, Entry II-I-67).

(a) When an instantaneous sample is desired and H_2S concentration is 10 grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than 10 grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart.) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top that connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.* (1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide (KI) for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml=0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) Starch solution. Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) *Procedure*. Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine through (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then,

Grains H_2S per 100 cubic foot of gas = 100 (D-C)

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.

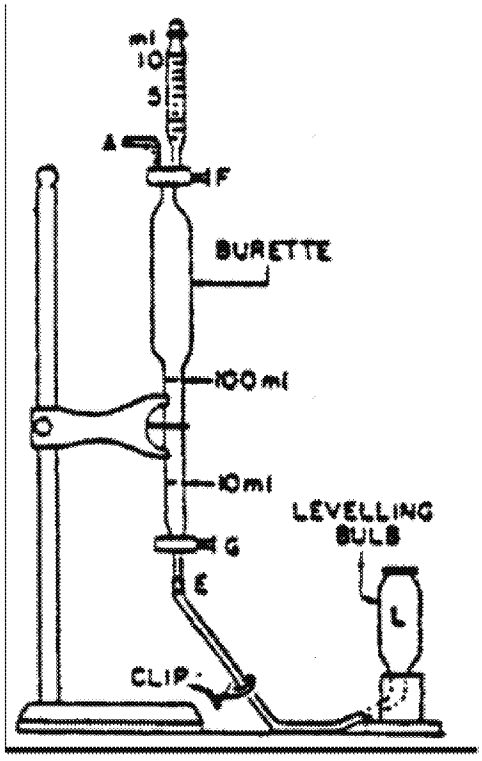

Figure 1. Tatwiler burette (lettered items mentioned in text).

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

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (j) of this section. The initial compliance period

begins on August 2, 2016, or upon initial startup, whichever is later, and ends no later than 1 year after the initial startup date for your affected facility or no later than 1 year after August 2, 2016. The initial compliance period may be less than one full year.

(a) To achieve initial compliance with the methane and VOC standards for each well completion operation conducted at your well affected facility you must comply with paragraphs (a)(1) through (4) of this section.

(1) You must submit the notification required in §60.5420a(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in §60.5420a(b)(1) and (2).

(3) You must maintain a log of records as specified in §60.5420a(c)(1)(i) through (iv), as applicable, for each well completion operation conducted during the initial compliance period. If you meet the exemption for wells with a GOR less than 300 scf per stock barrel of oil produced, you do not have to maintain the records in §60.5420a(c)(1)(i) through (iv) and must maintain the record in §60.5420a(c)(1)(vi).

(4) For each well affected facility subject to both §60.5375a(a)(1) and (3), as an alternative to retaining the records specified in §60.5420a(c)(1)(i) through (iv), you may maintain records in accordance with §60.5420a(c)(1)(v) of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment

connected and operating at each well completion operation with a photograph of a separately operating GPS device within the same digital picture, provided the latitude and longitude output of the GPS unit can be clearly read in the digital photograph.

(b)(1) To achieve initial compliance with standards for your centrifugal compressor affected facility you must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required by §60.5380a(a) and as demonstrated by the requirements of §60.5413a.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of §60.5411a(b) that is connected through a closed vent system that meets the requirements of §60.5411a(a) and (d) and is routed to a control device that meets the conditions specified in §60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

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

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

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

(6)]Reserved]

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in §60.5420a(b)(1) and (3).

(8) You must maintain the records as specified in §60.5420a(c)(2), (6) through (11), and (17), as applicable.

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

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

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

(3) You must submit the initial annual report for your reciprocating compressor as required in §60.5420a(b)(1) and (4).

(4) You must maintain the records as specified in §60.5420a(c)(3) for each reciprocating compressor affected facility.

(d) To achieve initial compliance with methane and VOC emission standards for your pneumatic controller affected facility you must comply with the requirements specified in paragraphs (d)(1) through (6) of this section, as applicable.

(1) You must demonstrate initial compliance by maintaining records as specified in §60.5420a(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required as specified in §60.5390a(b)(1) or (c)(1).

(2) If you own or operate a pneumatic controller affected facility located at a natural gas processing plant, your pneumatic controller must be driven by a gas other than natural gas, resulting in zero natural gas emissions.

(3) If you own or operate a pneumatic controller affected facility located other than at a natural gas processing plant, the controller manufacturer's design specifications for the controller must indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

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

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of §60.5420a(b)(1) and (5).

(6) You must maintain the records as specified in §60.5420a(c)(4) for each pneumatic controller affected facility.

(e) To achieve initial compliance with emission standards for your pneumatic pump affected facility you must comply with the requirements specified in paragraphs (e)(1) through (7) of this section, as applicable.

(1) If you own or operate a pneumatic pump affected facility located at a natural gas processing plant, your pneumatic pump must be driven by a gas other than natural gas, resulting in zero natural gas emissions.

(2) If you own or operate a pneumatic pump affected facility located at a well site, you must reduce emissions in accordance with §60.5393a(b)(1) or (b)(2), and you must collect the

pneumatic pump emissions through a closed vent system that meets the requirements of §60.5411a(c) and (d).

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

(5) If you own or operate a pneumatic pump affected facility 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(c) and (d).

(6) You must submit the initial annual report for your pneumatic pump affected facility required in §60.5420a(b)(1) and (8).

(7) You must maintain the records as specified in §60.5420a(c)(6), (8) through (10), (16), and (17), as applicable, for each pneumatic pump affected facility.

(8) [Reserved]

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the methane and VOC standards is demonstrated if you are in compliance with the requirements of §60.5400a.

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

(1) To determine compliance with the standards for SO_2 specified in §60.5405a(a), during the initial performance test as required by §60.8, the minimum required sulfur dioxide emission

reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406a(c)(1).

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

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

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

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

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

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

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

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

(i) For each storage vessel affected facility that complies by using a floating roof, you must submit a statement that you are complying with §60.112(b)(a)(1) or (2) in accordance with §60.5395a(b)(2) with the initial annual report specified in §60.5420a(b).

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

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

(2) You must conduct an initial monitoring survey as required in §60.5397a(f).

(3) You must maintain the records specified in §60.5420a(c)(15).

(4) You must repair each identified source of fugitive emissions for each affected facility as required in §60.5397a(h).

(5) You must submit the initial annual report for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station compressor station as required in §60.5420a(b)(1) and (7).

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

EFFECTIVE DATE NOTE: At 82 FR 25733, June 5, 2017, in §60.5410a, paragraphs (e)(2) through (5) and paragraph (j) were stayed until Aug. 31, 2017.

§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).

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by §60.5416a(b).

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

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

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere that is capable of taking periodic readings as specified in §60.5416a(a)(4)(i) and sounds an alarm, or initiates notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to §60.5420a(c)(8).

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

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

(b) Cover requirements for storage vessels and centrifugal compressor wet seal fluid degassing systems.

(1) The cover and all openings on the cover (*e.g.*, access hatches, sampling ports, pressure relief devices and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.*, covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed vent system designed and operated in accordance with the requirements of paragraph (a) or (c), and (d), of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(c) Closed vent system requirements for storage vessel and 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 material in the storage vessel or pneumatic pump to a control device or to a process. For storage vessels, the closed vent system must route all gases, vapors, and fumes to a control device that meets the requirements specified in §60.5412a(c) and (d).

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections.

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

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

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

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

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

(d) Closed vent systems requirements for centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels using a control device or routing emissions to a process.

(1) You must conduct an assessment that the closed vent system is of sufficient design and capacity to ensure that all emissions from the 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 an in-house engineer or a qualified professional engineer in accordance with paragraphs (d)(1)(i) and (ii) of this section.

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

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

(2) [Reserved]

(e) [Reserved]

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

EFFECTIVE DATE NOTE: At 82 FR 25733, June 5, 2017, in §60.5411a, paragraph (d) was stayed until Aug. 31, 2017.

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

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

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

(1) Each combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section. 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.

(i) You must reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413a(b), with the exceptions noted in §60.5413a(a).

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of §60.5413a(b), with the exceptions noted in §60.5413a(a).

(iii) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under §60.5413a(b), that combustion zone temperature is an indicator of destruction efficiency.

(iv) 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.

(2) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413a(b). As an alternative to the performance testing requirements, you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of §60.5413a(c).

(3) You must design and operate a flare in accordance with the requirements of §60.18(b), and you must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(b) You must operate each control device installed on your centrifugal compressor affected facility in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system affected facility as required under §60.5380a(a)(1) through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of §60.5417a(a) through (g), you must demonstrate compliance according to the requirements of §60.5415a(b)(2), as applicable.

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

(1) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to §60.5413a(c)(2) or (3) or according to the design required in paragraph (d)(2) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in §60.5420a(c)(10) and (12).

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vi) of this section.

(i) Regenerate or reactivate the spent carbon in a unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a unit equipped with an operating organic air emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 63 or this part.

(iii) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(iv) Burn the spent carbon in a hazardous waste boiler or industrial furnace for which the owner or operator complies with the requirements of 40 CFR part 63, subpart EEE and has submitted a Notification of Compliance under 40 CFR 63.1207(j).

(v) Burn the spent carbon in an industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vi) Burn the spent carbon in an industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(d) Each control device used to meet the emission reduction standard in §60.5395a(a)(2) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (4) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under §60.5413a(d), which meets the criteria in §60.5413a(d)(11) and meet the continuous compliance requirements in §60.5413a(e).

(1) For each combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.

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

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

(iii) Operate the combustion control device with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22 of appendix A-7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair

activity, each device must pass a Method 22 of appendix A-7 of this part visual observation as described in this paragraph.

(iv) Each enclosed combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (A) through (D) of this section. 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.

(A) You must reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of §60.5413a(b).

(B) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 275 parts per million by volume as propane on a wet basis corrected to 3 percent oxygen as determined in accordance with the applicable requirements of §60.5413a(b).

(C) You must operate at a minimum temperature of 760 °Celsius, provided the control device has demonstrated, during the performance test conducted under §60.5413a(b), that combustion zone temperature is an indicator of destruction efficiency.

(D) 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.

(2) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(3) You must design and operate a flare in accordance with the requirements of §60.18(b), and you must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(4) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

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

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your centrifugal compressor affected facility or storage vessel affected facility. You must demonstrate that a control device achieves the performance requirements of §60.5412a(a)(1) or (2) or (d)(1) or (2) using the performance test methods and procedures specified in this section. For condensers and carbon adsorbers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion control device performance tests conducted by the manufacturer applicable to storage vessel and centrifugal compressor affected facilities.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) A flare that is designed and operated in accordance with §60.18(b). You must conduct the compliance determination using Method 22 of appendix A-7 of this part to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H; you have submitted a Notification of Compliance under 40 CFR 63.1207(j) and comply with the requirements of 40 CFR part 63, subpart EEE; or you comply with 40 CFR part 63, subpart EEE and will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in §60.5420(b)(9) for submitting the initial performance test report.

(5) A hazardous waste incinerator for which you have submitted a Notification of Compliance under 40 CFR 63.1207(j), or for which you will submit a Notification of Compliance under 40 CFR 63.1207(j) by the date specified in §60.5420a(b)(9) for submitting the initial performance test report, and you comply with the requirements of 40 CFR part 63, subpart EEE.

(6) A performance test is waived in accordance with §60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of §60.5412a(a)(1) or (d)(1) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of §60.5412a(a)(1) or (2) or (d)(1) or (2). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section. Each performance test must consist of a minimum of 3 test runs. Each run must be at least 1 hour long.

(1) You must use Method 1 or 1A of appendix A-1 of this part, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device and at the outlet of the final control device to determine compliance with a control device percent reduction requirement.

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with a TOC exhaust gas concentration limit.

(2) You must determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of appendix A-2 of this part, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in §60.5412a(a)(1)(i), (a)(2) or (d)(1)(iv)(A), you must use Method 25A of appendix A-7 of this part. You must use Method 4 of appendix A-3 of this part to convert the Method 25A results to a dry basis. You must use the procedures in paragraphs (b)(3)(i) through (iii) of this section to calculate percent reduction efficiency.

(i) You must compute the mass rate of TOC using the following equations:

$E_i = K_2 C_i M_p Q_i$

$E_o = K_2 C_o M_p Q_o$

Where:

E_i, E_o = Mass rate of TOC at the inlet and outlet of the control device, respectively, dry basis, kilograms per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 °Celsius.

C_i, C_o = Concentration of TOC, as propane, of the gas stream as measured by Method 25A at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_p = Molecular weight of propane, 44.1 gram/gram-mole.

Q_i, Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

(ii) You must calculate the percent reduction in TOC as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

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Where:

R_{cd} = Control efficiency of control device, percent.

E_i, = Mass rate of TOC at the inlet to the control device as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

E_o = Mass rate of TOC at the outlet of the control device, as calculated under paragraph (b)(3)(i) of this section, kilograms per hour.

(iii) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC across the device by comparing the TOC in all combusted vent streams and primary and secondary fuels with the TOC exiting the device, respectively.

(4) You must use Method 25A of appendix A-7 of this part to measure TOC, as propane, to determine compliance with the TOC exhaust gas concentration limit specified in §60.5412a(a)(1)(ii) or (d)(1)(iv)(B). You may also use Method 18 of appendix A-6 of this part to measure methane and ethane. You may subtract the measured concentration of methane and ethane from the Method 25A measurement to demonstrate compliance with the concentration limit. You must determine the concentration in parts per million by volume on a wet basis and correct it to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) If you use Method 18 to determine methane and ethane, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run. You must determine the average methane and ethane concentration per run. The samples must be taken during the same time as the Method 25A sample.

(ii) You may subtract the concentration of methane and ethane from the Method 25A TOC, as propane, concentration for each run.

(iii) You must correct the TOC concentration (minus methane and ethane, if applicable) to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B of appendix A-2 of this part, ASTM D6522-00

(Reapproved 2011), or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m\left(\frac{17.9}{20.9 - \%O_{2m}}\right)$$

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Where:

C_c = TOC concentration, as propane, corrected to 3 percent oxygen, parts per million by volume on a wet basis.

C_m = TOC concentration, as propane, (minus methane and ethane, if applicable), parts per million by volume on a wet basis.

$\%O_{2m}$ = Concentration of oxygen, percent by volume as measured, wet.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in §60.5420a(b)(9).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic

performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in §60.5420a(b)(9).

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section. For centrifugal compressor affected facilities, if you do not continuously monitor the gas flow rate in accordance with §60.5417a(d)(1)(viii), then you must comply with the periodic performance testing requirements of paragraph (b)(5)(ii).

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in §60.5412a(a)(1)(ii) or (d)(1)(iv)(B) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level. For centrifugal compressor affected facilities, you must establish a limit on temperature in accordance with §60.5417a(f) and continuously monitor the temperature as required by §60.5417a(d).

(c) *Control device design analysis to meet the requirements of §60.5412a(a)(2) or (d)(2).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete

carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity and temperature and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems shall incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

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

(2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a

total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

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

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

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

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

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device

operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

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

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

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

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

(i) At the inlet gas sampling location, securely connect a 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.

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

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

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

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

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945-03 (incorporated by reference as specified in §60.17).

(B) Hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945-03 (incorporated by reference as specified in §60.17).

(C) Higher heating value using ASTM D3588-98 or ASTM D4891-89 (incorporated by reference as specified in §60.17).

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

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) and (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using Method 1 of appendix A-1 of this part for determining flow measurement traverse point location, and Method 2 of appendix A-1 of this part for measuring duct velocity. If low flow conditions are encountered (*i.e.*, velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

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

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

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

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

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

(i) An integrated bag sample must be collected during the moisture test required by Method 4 of appendix A-3 of this part following the procedure specified in (d)(7)(i)(A) and (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC-TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) and (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC-TCD calibration procedure in Method 3C of appendix A-2 of this part must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using Method 4 of appendix A-3 of this part. Traverse both ports with the sampling train required by Method 4 of appendix A-3 of this part during each test run. Ambient air must not be introduced into the integrated bag sample required by Method 3C of appendix A-2 of this part during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B of appendix A-2 of this part, equation 3B-1, or ANSI/ASME PTC 19.10-1981, Part 10 (manual portion only) (incorporated by reference as specified in §60.17).

(8) Carbon monoxide must be determined using Method 10 of appendix A-4 of this part. Run the test simultaneously with Method 25A of appendix A-7 of this part using the same sampling points. An instrument range of 0-10 parts per million by volume-dry (ppmvd) is recommended.

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

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

(ii) A valid test must consist of three Method 25A tests, each no less than 60 minutes in duration.

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

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—"EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards," (incorporated by reference as specified in §60.17).

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO_2, as measured by Method 3C of appendix A-2 of this part. You must use the following equation for this diluent concentration correction:

$$C_{corr} = C_{meas}\left(\frac{3}{CO_{2meas}}\right)$$

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Where:

C_{meas} = The measured concentration of the pollutant.

CO_{2meas} = The measured concentration of the CO_2 diluent.

3 = The corrected reference concentration of CO_2 diluent.

C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using Method 22 of appendix A-7 of this part. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Results from Method 22 of appendix A-7 of this part determined under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average results from Method 25A of appendix A-7 of this part determined under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2.

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

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

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

(iii) A manufacturer must demonstrate a destruction efficiency of at least 95 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95 percent for THC, as propane, will meet the control requirement for 95 percent destruction of VOC and methane (if applicable) required under this subpart.

(12) The owner or operator of a combustion control device model tested under this paragraph must submit the information listed in paragraphs (d)(12)(i) through (vi) of this section 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) CBIO Room 521; 109 T.W. Alexander Drive; RTP, NC 27711. The same file with the CBI omitted must be submitted to *Oil_and_Gas_PT@EPA.GOV*.

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess air range.

(G) Flame arrestor(s).

(H) Burner manifold.

(I) Pilot flame indicator.

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

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

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

(e) *Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph (e) applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance criteria in paragraph (d)(11) of this section by installing a device tested under paragraph (d) of this section, complying with the criteria specified in paragraphs (e)(1) through (8) of this section, maintaining the records specified in §60.5420a(c)(2) or (c)(5)(vi) and submitting the report specified in §60.5420a(b)(10).

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to

section 11 of EPA Method 22 of appendix A-7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass a visual observation according to EPA Method 22 of appendix A-7 of this part as described in paragraph (e)(3) of this section.

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

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

(8) Operate each control device following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions.

§60.5415a How do I demonstrate continuous compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, and collection of

fugitive emissions components at a compressor station affected facilities, and affected facilities at onshore natural gas processing plants?

(a) For each well affected facility, you must demonstrate continuous compliance by submitting the reports required by §60.5420a(b)(1) and (2) and maintaining the records for each completion operation specified in §60.5420a(c)(1).

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

(1) You must reduce methane and VOC emissions from the wet seal fluid degassing system by 95.0 percent or greater.

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of §60.5412a(a) using the procedures specified in paragraphs (b)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in §60.5412a(a)(2), you may demonstrate compliance according to paragraph (b)(2)(viii) of this section. You may switch between compliance with paragraphs (b)(2)(i) through (vii) of this section and compliance with paragraph (b)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, following the change.

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

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with §60.5417a(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (b)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (b)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in §60.5413a(d), compliance with the operating parameter limit is achieved when the criteria in §60.5413a(e) are met.

(iv) You must operate the continuous monitoring system required in §60.5417a(a) at all times the affected source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is any sudden, infrequent, not reasonably preventable failure of the monitoring system to provide valid data. Monitoring system failures that are caused in part by poor maintenance or careless operation are not malfunctions. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, or required monitoring system quality assurance or control activities in calculations used to report emissions or operating levels. You

must use all the data collected during all other required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of §60.5412a(a)(1) and you demonstrate compliance using the test procedures specified in §60.5413a(b), or you use a flare designed and operated in accordance with §60.18(b), you must comply with paragraphs (b)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A-7 of this part visual observation as described in paragraph (b)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in §60.5412a(a)(2), you must demonstrate compliance using the procedures in paragraphs (b)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to §60.5417a(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with §60.5417a(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (b)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (b)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (b)(2)(viii)(D)(*1*) and (*2*) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (b)(2)(viii)(C) of this section.

(*1*) After the compliance dates specified in §60.5370a(a), if you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation after the compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(*2*) After 120 days and no more than 364 days of operation after the compliance date specified in §60.5370a(a), you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (b)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

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

(4) [Reserved]

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

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

(2) You must submit the annual reports as required in §60.5420a(b)(1) and (4) and maintain records as required in §60.5420a(c)(3).

(3) You must replace the reciprocating compressor rod packing on or before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) You must operate the rod packing emissions collection system under negative pressure and continuously comply with the cover and closed vent requirements in §60.5416a(a) and (b).

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in §60.5390a(a), (b), or (c).

(2) You must submit the annual reports as required in §60.5420a(b)(1) and (5).

(3) You must maintain records as required in §60.5420a(c)(4).

(e) You must demonstrate continuous compliance according to paragraph (e)(3) of this section for each storage vessel affected facility, for which you are using a control device or routing emissions to a process to meet the requirement of §60.5395a(a)(2).

(1)-(2) [Reserved]

(3) For each storage vessel affected facility, you must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) You must reduce VOC emissions as specified in §60.5395a(a)(2).

(ii) For each control device installed to meet the requirements of §60.5395a(a)(2), you must demonstrate continuous compliance with the performance requirements of §60.5412a(d) for each storage vessel affected facility using the procedure specified in paragraph (e)(3)(ii)(A) and either (e)(3)(ii)(B) or (e)(3)(ii)(C) of this section.

(A) You must comply with §60.5416a(c) for each cover and closed vent system.

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

(C) Each closed vent system that routes emissions to a process must be operated as specified in §60.5411a(c)(2) and (3).

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with methane and VOC requirements is demonstrated if you are in compliance with the requirements of §60.5400a.

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

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in §60.5406a(c)(1).

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

(1) You must conduct periodic monitoring surveys as required in §60.5397a(g).

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

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

(4) You must submit annual reports for collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in §60.5420a(b)(1) and (7).

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

EFFECTIVE DATE NOTE: At 82 FR 25733, June 5, 2017, in §60.5415a, paragraph (h) was stayed until Aug. 31, 2017.

§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 (c) of this section.

(a) Inspections for closed vent systems and covers installed on each centrifugal compressor or reciprocating compressor affected facility. Except as provided in paragraphs (b)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (e.g., a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(ii) Conduct annual inspections according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections;

liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results as specified in §60.5420a(c)(6).

(3) For each cover, you must meet the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) You must initially conduct the inspections specified in paragraph (a)(3)(i) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (b)(11) and (12) of this section. You must maintain records of the inspection results as specified in §60.5420a(c)(7).

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

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the

non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to §60.5420a(c)(8).

(b) No detectable emissions test methods and procedures. If you are required to conduct an inspection of a closed vent system or cover at your centrifugal compressor, reciprocating compressor, or pneumatic pump affected facility as specified in paragraphs (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21 of appendix A-7 of this part.

(2) The detection instrument must meet the performance criteria of Method 21 of appendix A-7 of this part, except that the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 of appendix A-7 of this part.

(4) Calibration gases must be as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 of appendix A-7 of this part.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (b)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 of appendix A-7 of this part, except the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (b)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (b)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (b)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (b)(9)(i) and (ii) of this section, except as provided in paragraph (b)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (b)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (b)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records.* Records shall be maintained as specified in this section and in §60.5420a(c)(9).

(c) *Cover and closed vent system inspections for pneumatic pump or 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 (c)(2) of this section. You must also comply with the requirements of (c)(3) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection at least once every calendar month as specified in paragraphs (c)(1)(i) through (iii) of this section.

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

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

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

(2) For each cover, you must conduct inspections at least once every calendar month as specified in paragraphs (c)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in §60.5420a(c)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

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

(3) For each bypass device, except as provided for in §60.5411a(c)(3)(ii), you must meet the requirements of paragraphs (c)(3)(i) or (ii) of this section.

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

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the

non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to §60.5420a(c)(8).

(4) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (c)(4)(i) through (iii) of this section, except as provided in paragraph (c)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (c)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (c)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (c)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(d) [Reserved]

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

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

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

(a) For each control device used to comply with the emission reduction standard for centrifugal compressor affected facilities in §60.5380a(a)(1), you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with §60.5412a(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section. If you install and operate an enclosed combustion device 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 (h)(4) of this section.

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

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan. Heat sensing monitoring devices that indicate the

continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (e.g., thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in §60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in §60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan. Heat sensing monitoring devices that indicate the continuous ignition a pilot flame are exempt from the calibration, quality assurance and quality control requirements in this section.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under §60.5413a(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame. The heat sensing monitoring device is exempt from the calibration requirements of this section.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the

temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5°Celsius, whichever value is greater.

(vii) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in §60.5413a(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under §60.5413a(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of

this section. If you comply with the periodic testing requirements of §60.5413a(b)(5)(ii), you are not required to continuously monitor the gas flow rate under paragraph (d)(1)(viii)(A) of this section.

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better at the maximum expected flow rate. The flow rate at the inlet to the combustion device must not exceed the maximum flow rate determined by the manufacturer.

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

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

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in §60.13(i).

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate and data from the heat sensing devices that indicate the presence of a pilot flame. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device

operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of §60.5412a(a)(1) or (2). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of §60.5413a(b) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412a(a)(1) or (2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of §60.5413a(c) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412a(a)(2), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under §60.5413a(d) to demonstrate that the control device achieves the applicable performance requirements specified in §60.5412a(a)(1), then your control device inlet gas flow rate must not exceed the maximum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of §60.5413a(b) to demonstrate that the condenser achieves the applicable performance requirements in §60.5412a(a)(2), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of §60.5413a(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in §60.5412a(a)(2), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this

section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section or when the heat sensing device indicates that there is no pilot flame present.

(2) If you are subject to §60.5412a(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in §60.5415a(b)(2)(viii)(D) is less than 95.0 percent.

(3) If you are subject to §60.5412a(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in §60.5415a(b)(2)(viii)(D)(*1*) or (*2*) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraph (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to §60.5411a(a)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to §60.5411a(a)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under §60.5413a(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) of this section are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under §60.5413a(d).

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

(h) For each control device used to comply with the emission reduction standard in §60.5395a(a)(2) for your storage vessel affected facility, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(4) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with §60.5413a(d)(2) through (10), which meets the criteria in §60.5413a(d)(11), the reporting requirement in §60.5413a(d)(12), and meet the continuous compliance requirement in §60.5413a(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (h)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22 of appendix A of this part. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

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

(iv) For any absence of the pilot flame, or other indication of smoking or improper equipment operation (*e.g.,* visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (h)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified in §60.5420a(c)(13).

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in §60.5413a(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

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

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

(1) If you own or operate an affected facility that is the group of all equipment within a process unit at an onshore natural gas processing plant, or a sweetening unit at an onshore natural gas processing plant, you must submit the notifications required in §60.7(a)(1), (3), and (4) and §60.15(d). If you own or operate a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, or collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station, you are not required to submit the notifications required in §60.7(a)(1), (3), and (4) 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 standard selected 90 days before implementing any of the provisions.

(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 for all reports.

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

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

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

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

(2) For each well affected facility 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 (b)(2)(xiv) of this section, if applicable. In lieu of submitting the records specified in paragraph (b)(2)(i) through (b)(2)(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 permanent separators, the records specified in paragraphs (b)(2)(i) through (b)(2)(iv) and (b)(2)(vi) through (b)(2)(xiv) of this section. For each well affected facility that is subject to §60.5375a(g), the record specified in paragraph (b)(2)(xv) of this section.

(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) US Well ID.

(iv) The date and time of the onset of flowback following hydraulic fracturing or refracturing

(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, how the defect or leak was repaired and 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 §60.5413a(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 later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

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

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

(vii) 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 §60.5413a(e), the information in paragraphs (b)(6)(vii)(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.

(viii) 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.

(ix) If required to comply with §60.5395a(b)(1), the information in paragraphs (b)(6)(ix)(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, how the defect or leak was repaired 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).

(7) For the collection of fugitive emissions components at each well site and the collection of fugitive emissions components at each compressor station within the company-defined area, the information specified in paragraphs (b)(7)(i) and (ii) of this section.

(i)(A) 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.

(B) 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 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 a statement that all major production and processing equipment has been removed from the well site, the date of the removal of the last piece of major production and processing equipment, and if the well site is still producing to another site, the well ID or separate tank battery ID receiving the production.

(D) For each collection of fugitive emissions components at a well site where you previously reported under paragraph (b)(7)(i)(C) 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.

(E) For the collection of fugitive emissions components at a compressor station, if a monitoring survey is waived under §60.5397a(g)(5), you must include in your annual report the fact that a monitoring survey was waived and the calendar months that make up the quarterly monitoring period for which the monitoring survey was waived.

(F) For each new collection of fugitive emissions components at a well site where the average combined oil and natural gas production for the wells at the site is less than 15 boe per day, you must submit the combined oil and natural gas production in boe for the wells at the site, averaged over the first 30 days of production.

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

(A) Date of the survey.

(B) Name or unique ID of operator(s) performing survey.

(C) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(D) Monitoring instrument used.

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

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

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

(H) Number and type of difficult-to-monitor and unsafe-to-monitor fugitive emission components monitored.

(I) The date of successful repair of the fugitive emissions component.

(J) Number and type of fugitive emission components currently on delay of repair and explanation for each delay of repair.

(K) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding, if the type of instrument is different from the type used during the initial fugitive emissions finding.

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

(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 paragraphs (b)(8)(i)(A), (B) or (C) of this section.

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

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

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

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

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

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

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

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

(iii) 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(c);

(B) Each defect or leak identified during each inspection, how the defect or leak was repaired 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 Web site (*G:\USER\SHARE_FIG\Oil & Gas\NSPS 3.0 Reconsiderations\Technical 5719.8\OMB Package*) at the time of the test, you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used

electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404-02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

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

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

(11) You must submit reports to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX (https://cdx.epa.gov/).) You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (https://www3.epa.gov/ttn/chief/cedri/). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 calendar days, you must begin submitting all subsequent reports via CEDRI. The reports must be submitted by the deadlines specified in this subpart, regardless of the method in which the reports are submitted. If you claim that some of the information required to be submitted via CEDRI is CBI, 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 Web site, 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, Measurement Policy 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.

(12) You must submit the certification signed by the in-house engineer or qualified professional 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, and due to a planned or actual outage of either the EPA's CEDRI or CDX systems within the period of time beginning 5 business days prior to the date that the submission is due, you will be or are precluded from accessing CEDRI or CDX and submitting a required report within the time prescribed, you may assert a claim of EPA system outage for failure to timely comply with the reporting requirement. 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. You must provide to the Administrator a written description identifying the date, time and length of the outage; a rationale for attributing the delay in reporting beyond the regulatory deadline to the EPA system outage; describe the measures taken or to be taken to minimize the delay in reporting; and identify a 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. In any circumstance, the report must be submitted electronically as soon as possible after the outage is resolved. 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.

(14) If you are required to electronically submit a report through CEDRI in the EPA's CDX and a force majeure event is about to occur, occurs, or has occurred within the period of time beginning 5 business days prior to the date the submission is due, the owner or operator may assert a claim of force majeure for failure to timely comply with the reporting requirement. 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). If you intend to assert a claim of force majeure, 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. You must provide to the Administrator a written description of the force majeure event and a rationale for attributing the delay in reporting beyond the regulatory deadline to the force majeure event; describe the measures taken or to be taken to minimize the delay in reporting; and identify a 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. In any circumstance, the reporting must occur as soon as possible after the force majeure event occurs. 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.

(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), only. For each well affected facility that routes flowback entirely through permanent separators the date and time of each attempt to direct flowback to a separator is not 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 that subparagraph.

(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(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 §60.5413a(e) and used to comply with §60.5380a(a)(1) for each centrifugal compressor.

(i) Make, model and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) Location of the centrifugal compressor and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in §60.5413a(e) as specified in paragraphs (c)(2)(vi)(A) through (E) of this section.

(A) Records that the pilot flame is present at all times of operation.

(B) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(C) Records of the maintenance and repair log.

(D) Records of the visible emissions test following return to operation from a maintenance or repair activity, 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 later. Alternatively, a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

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

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in §60.5385a, 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), 60.5416a(c)(6)(ii), and 60.5416a(c)(7)(ii). You must maintain the records in paragraph (c)(5)(vi) of this part for each control device tested under §60.5413a(d) which meets the criteria in §60.5413a(d)(11) and §60.5413a(e) and used to comply with §60.5395a(a)(2) for each storage vessel.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under §60.5365a(e) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) 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 oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment. If a storage vessel is removed from a site and, within 30 days, is either returned to the site or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the

original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(v) You must maintain records of the identification and location 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 §60.5413a(e) and used to comply with §60.5395a(a)(2) for each storage vessel.

(A) Make, model and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in §60.5413a(e) as specified in paragraphs (c)(5)(vi)(F)(*1*) through (*5*) of this section.

(*1*) Records that the pilot flame is present at all times of operation.

(*2*) Records that the device was operated with no visible emissions except for periods not to exceed a total of 1 minute during any 15 minute period.

(*3*) Records of the maintenance and repair log.

(*4*) Records of the visible emissions test following return to operation from a maintenance or repair activity, 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) for centrifugal compressors and reciprocating compressors, or §60.5416a(c)(1) for storage vessels and pneumatic pumps as required in paragraphs (c)(6)(i) through (iii) of this section.

(i) A record of each closed vent system inspection. 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 detected during inspections required by §60.5416a(a)(1) and (2) or §60.5416a(c)(1), 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), 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 or pneumatic pumps as required in paragraphs (c)(7)(i) through (iii) of this section.

(7) The records for the cover inspection required under §60.5416a(a)(3) for centrifugal or reciprocating compressors or §60.5416a(c)(2) or (d)(3) for storage vessels or pneumatic pumps, 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 §60.5416a(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), 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) If you are subject to the closed vent system no detectable emissions requirements of §60.5416a(b) for centrifugal compressors or reciprocating compressors, you must prepare and maintain the records required in paragraphs (c)(9)(i) through (iii) of this section.

(i) A record of each closed vent system 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 monitoring survey.

(ii) For each leak detected during inspections required by §60.5416a(b), you must record the location of the leak, the maximum concentration reading obtained using Method 21, the date of detection, the corrective action taken the repair the leak, and the date the repair to correct the leak is completed.

(iii) If repair of the leak 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.

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

(11) For each centrifugal compressor affected facility subject to the control device requirements of §60.5412a(a), (b), and (c), records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of

continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(12) For each carbon adsorber installed on storage vessel affected facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of §60.5412a(d)(2)) and records of each carbon replacement as specified in §60.5412a(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of §60.5412a(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in §60.5417a(h)(3). You must maintain records of EPA Method 22 of appendix A-7 of this part, section 11 results, which include: Company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22-1 in EPA Method 22 of appendix A-7 of this part. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

(14) A log of records as specified in §60.5412a(d)(1)(iii), for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

(15) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, the records identified in paragraphs (c)(15)(i) through (vii) 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 compressor station.

(ii) 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, 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, 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, the date that the first piece of major production and processing equipment is added back to the well site.

(iii) For each collection of fugitive emissions components at a well site that is monitored annually under (g)(1)(ii)(B), the records identified in paragraphs (c)(15)(iii)(A) and (B) of this section.

(A) The average daily combined oil and natural gas production for the well site during the first 30 days of production; and

(B) A description of the methodology used to calculate the daily average production for the well site.

(iv) The fugitive emissions monitoring plan as required in §60.5397a(b), (c), and (d).

(v) The records of each monitoring survey as specified in paragraphs (c)(15)(v)(A) through (L) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s) performing survey. If you choose to report the unique ID of the operator(s) performing the survey in lieu of the operator(s) name, you must keep a record linking

the unique ID to the operator(s) name. You must note the training and experience of the operator(s).

(D) Monitoring instrument used.

(E) When optical gas imaging is used to perform the survey, one or more digital photographs or videos, captured from the optical gas imaging instrument used for conduct of monitoring, of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital file, the digital photograph or video may consist of an image of the monitoring survey being performed with a separately operating GPS device within the same digital picture or video, provided the latitude and longitude output of the GPS unit can be clearly read in the digital image. Digital photographs or video recorded under paragraph (c)(15)(v)(K)(*1*) of this section can be used to meet this requirement, as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.

(F) Fugitive emissions component identification when Method 21 is used to perform the monitoring survey or when OGI is used to perform the monitoring survey and the owner or operator chooses to comply with §60.5397a(d)(2) in lieu of §60.5397a (d)(1).

(G) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(H) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(I) Documentation of each fugitive emission, including the information specified in paragraphs (c)(15)(v)(I)(*1*) through (*3*) of this section.

(*1*) Location.

(*2*) Component ID and type of fugitive emissions component.

(*2*) Component ID.

(*3*) Instrument reading of each fugitive emissions component that requires repair when Method 21 is used for monitoring.

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

(K) For each component that cannot be repaired during the monitoring survey when the fugitive emissions were initially found:

(*1*) Number and type of components that were tagged or a digital photograph or video of each fugitive emissions component. The digital photograph or video must clearly identify the location of the component that must be repaired. Any digital photograph or video required under this paragraph can also be used to meet the requirements under paragraph (c)(15)(ii)(E) of this section, as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.

a digital photograph or video. The digital photograph or video must clearly identify the location of the component that must be repaired. Any digital photograph or video required under this paragraph can also be used to meet the requirements under paragraph (c)(15)(ii)(E) of this section, as long as the photograph or video is taken with the optical gas imaging instrument, includes the date and the latitude and longitude are either imbedded or visible in the picture.

(*2*) The date and repair methods applied in each attempt to repair the fugitive emissions components.

(*3*) The date of successful repair of the fugitive emissions component.

(*4*) The date of each resurvey and instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(*5*) Identification of each fugitive emission component placed on delay of repair and explanation for each delay of repair.

(L) Records of calibrations for the instrument used during the monitoring survey.

(vi) Date of planned shutdowns that occur while there are any components that have been placed on delay of repair.

(vii) For the collection of fugitive emissions components at a compressor station, if a monitoring survey is waived under §60.5397a(g)(5), you must maintain records of the average calendar month temperature, including the source of the information, for each calendar month of the quarterly monitoring period for which the monitoring survey was waived.

(16) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(16)(i) through (v) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic pump constructed, modified or reconstructed.

(ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in §60.5393a, 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, manufacturer's specifications, and if the control device is designed

to achieve less than 95 percent emission reduction, a design evaluation or manufacturer's specifications indicating the percentage reduction achieved the control device is designed to achieve.

(iv) Records substantiating a claim according to §60.5393a(b)(5) that it is technically infeasible to capture and route emissions from a pneumatic pump to a control device or process; including the certification according to §60.5393a(b)(5)(ii) and the records of the engineering assessment of technical infeasibility performed according to §60.5393a(b)(5)(iii).

(v) You must retain copies of all certifications, engineering assessments and related records for a period of five years and make them available if directed by the implementing agency.

(17) For each closed vent system routing to a control device or process, the records of the assessment conducted according to §60.5411a(d):

(i) A copy of the assessment conducted according to §60.5411a(d)(1);

(ii) A copy of the certification according to §60.5411a(d)(1)(i); and

(iii) The owner or operator shall retain copies of all certifications, assessments and any related records for a period of five years, and make them available if directed by the delegated authority.

(18) A copy of each performance test submitted under paragraph (b)(9) of this section.

[81 FR 35898, June 3, 2016, as amended at 82 FR 25733, June 5, 2017]

EFFECTIVE DATE NOTE: At 82 FR 25733, June 5, 2017, in §60.5420a, paragraphs (b)(7), (8), (12) and (c)(15) through (17) were stayed until Aug. 31, 2017.

§ 60.5421a What are my additional recordkeeping requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of §60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of §60.5401a(b)(1).

(1) When each leak is detected as specified in §60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in §60.5401a(b)(2), the information specified in paragraphs (b)(2)(i) through (x) of this section must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) "Above 500 ppm" if the maximum instrument reading measured by the methods specified in §60.5400a(d) after each repair attempt is 500 ppm or greater.

(v) "Repair delayed" and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of §60.482-4a(a). The designation of equipment subject to the provisions of §60.482-4a(a) must be signed by the owner or operator.

§ 60.5422a What are my additional reporting requirements for my affected facility subject to GHG and VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of §60.487a(a), (b)(1) through (3), (b)(5), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*https://www3.epa.gov/ttn/chief/cedri/*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in §60.4. Once the form has been available in CEDRI for at least 90 days, you must begin submitting all subsequent reports via CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in §60.487a(b)(1) through (3) and (b)(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 (c)(2)(vii) through (viii):

(1) Number of pressure relief devices for which leaks were detected as required in §60.5401a(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in §60.5401a(b)(3).

§ 60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

(a) You must retain records of the calculations and measurements required in §60.5405a(a) and (b) and §60.5407a(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under §60.7(f) of the General Provisions.

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. The 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.

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of §60.5407a(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone

of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of §60.5407a(b)(3). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(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.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less than 2 LT/D of H2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(d) If you elect to comply with §60.5407a(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H2S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state. Electronic reporting to the EPA cannot be waived, and as such, the provisions of this

paragraph do not relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

§ 60.5425a What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§60.1 through 60.19 apply to you.

§ 60.5430a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Artificial lift equipment means mechanical pumps including, but not limited to, rod pumps and electric submersible pumps used to flowback fluids from a well.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(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 equations: $Y = 1.0 - 0.575 \log X$, where X is 2015 minus the year of construction, and $Y = 1.0$ when the year of construction is 2015; and

(iii) The applicable basic annual asset guideline repair allowance, B, is 4.5.

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities 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 Clean Air Act or the regulations promulgated thereunder are concerned; or

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

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.

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

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions. Completion combustion devices include pit flares.

Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, or located at an onshore natural gas processing plant, is not a compressor station for purposes of §60.5397a.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

Crude oil and natural gas source category means:

(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and

(2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.

Custody 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.

Custody transfer means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or

other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) Fails to meet any term or condition that is adopted to implement an applicable requirement in this subpart and that is included in the operating permit for any affected source required to obtain such a permit; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

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

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

First attempt at repair means, for the purposes of fugitive emissions components, an action taken for the purpose of stopping or reducing fugitive emissions of methane or VOC 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.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas to a processing facility or a mainline pipeline.

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

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Gas to oil ratio (GOR) means the ratio of the volume of gas at standard temperature and pressure that is produced from a volume of oil when depressurized to standard temperature and pressure.

Hydraulic fracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in §60.485a(e) or §60.5401a(f)(2).

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

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

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

Intermittent/snap-action pneumatic controller means a pneumatic controller that is designed to vent non-continuously.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Liquid collection system means tankage and/or lines at a well site to contain liquids from one or more wells or to convey liquids to another site.

Local distribution company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

Low pressure well means a well that satisfies at least one of the following conditions:

(1) The static pressure at the wellhead following fracturing but prior to the onset of flowback is less than the flow line pressure;

(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 compressors, glycol dehydrators, heater/treaters, pneumatic pumps, pneumatic controllers, 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 daily throughput means the calculation of maximum daily throughput during the 30-day PTE evaluation period employing generally accepted methods.

Natural gas-driven diaphragm pump means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and

their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Permanent separator means a separator that handles flowback from a well or wells beginning when the flowback period begins and continuing to the startup of production.

Plug drill-out means the removal of a plug (or plugs) that was used to conducted hydraulic fracturing in different sections of the well.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Qualified Professional Engineer means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers making these certifications must be currently licensed in at least one state in which the certifying official is located.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere, or other mechanism that provides the same function.

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

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

Reduced emissions completion means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

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

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 of this subpart and is 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.

Returned to service means that a storage vessel affected facility that was removed from service has been:

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

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

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

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

Screenout means the first attempt to clear proppant from the wellbore through flowing the well to a fracture tank in order to achieve maximum velocity and carry the proppant out of the well.

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

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

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395a(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420a(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

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

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

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A-6 of this part.

Total SO_2 equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

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.

Underground storage vessel means a storage vessel stored below ground.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a well affected facility.

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

Well site means one or more surface sites that are constructed for the drilling and subsequent operation of any oil well, natural gas well, or injection well. For purposes of the

fugitive emissions standards at §60.5397a, well site also means a separate tank battery surface site collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries). 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 and (2) the flange upstream of the custody meter assembly and equipment, including fugitive emissions components, located downstream of this flange.

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

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.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

§60.5432a How do I determine whether a well is a low pressure well using the low pressure well equation?

(a) To determine that your well is a low pressure well subject to §60.5375a(f), you must determine whether the characteristics of the well are such that the well meets the definition of low pressure well in §60.5430a. To determine that the well meets the definition of low pressure well in §60.5430a, you must use the low pressure well equation below:

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

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Where:

(1) P_L is the pressure of flowback fluid immediately before it enters the flow line, expressed in pounds force per square inch (psia), and is to be calculated using the equation above;

(2) P_R is the pressure of the reservoir containing oil, gas, and water at the well site, expressed in psia;

(3) L is the true vertical depth of the well, expressed in feet (ft);

(4) q_o is the flow rate of oil in the well, expressed in cubic feet/second (cu ft/sec);

(5) q_g is the flow rate of gas in the well, expressed in cu ft/sec;

(6) q_w is the flow rate of water in the well, expressed in cu ft/sec;

(7) ρ_o is the density of oil in the well, expressed in pounds mass per cubic feet (lbm/cu ft).

(b) You must determine the four values in paragraphs (a)(4) through (7) of this section, using the calculations in paragraphs (b)(1) through (b)(15) of this section.

(1) Determine the value of the bottom hole pressure, P_{BH} (*psia*), based on available information at the well site, or by calculating it using the reservoir pressure, P_R (*psia*), in the following equation:

$$P_{BH}\ (psia) = \frac{1}{2} P_R$$

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(2) Determine the value of the bottom hole temperature, T_{BH} (F), based on available information at the well site, or by calculating it using the true vertical depth of the well, L *(ft)*, in the following equation:

$$T_{BH}\ (F) = (0.014 \times L) + 79.081$$

(3) Calculate the value of the applicable natural gas specific gravity that would result from a separator pressure of 100 psig, γ_{gs}, using the following equation with: Separator at standard conditions (pressure, p = 14.7 (*psia*), temperature, T = 60 (*F*)); the oil API gravity at the well site, γ_0; and the gas specific gravity at the separator under standard conditions, γ_{gp} = 0.75:

$$\gamma_{gs} = \gamma_{gp} \cdot \left(1.0 + 5.912 \times 10^{-5} \cdot \gamma_o \cdot T \cdot log\left(\frac{p}{114.7}\right)\right)$$

(4) Calculate the value of the applicable dissolved GOR, *Rs (scf/STBO)*, using the following equation with: The bottom hole pressure, P_{BH} (*psia*), determined in (b)(1) of this section; the bottom hole temperature, T_{BH} (*F*), determined in (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs}, calculated in (b)(3) of this section; the oil API gravity, γ_o, at the well site; and the constants, C1, C2, and C3, found in Table A:

$$R_s\left(\frac{scf}{STBO}\right) = C1 \cdot \gamma_{gs} \cdot P_{BH}{}^{C2} \cdot exp\left[C3\left(\frac{\gamma_o}{T_{BH} + 460}\right)\right]$$

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TABLE A—COEFFICIENTS FOR THE CORRELATION FOR R_S

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	0.0362	0.0178
C2	1.0937	1.1870
C3	25.7240	23.931

(5) Calculate the value of the oil formation volume factor, *Bo (bbl/STBO)*, using the following equation with: the bottom hole temperature, T_{BH} (*F*), determined in paragraph (b)(2) of this section; the gas gravity at separator pressure of 100 psig, γ_{gs}, calculated in paragraph (b)(3) of this section; the dissolved GOR, Rs (scf/STBO), calculated in paragraph (b)(4) of this section; the oil API gravity, γo, at the well site; and the constants, C1, C2, and C3, found in Table B:

$$B_o\left(\frac{bbl}{STBO}\right) = 1.0 + C1 \cdot R_s + (T_{BH} - 60)\left(\frac{\gamma_o}{\gamma_{gs}}\right) \cdot (C2 + C3 \cdot R_s)$$

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TABLE B—COEFFICIENTS FOR THE CORRELATION FOR B_o

Constant	$\gamma_{API} \leq 30$	$\gamma_{API} > 30$
C1	4.677×10^{-4}	4.670×10^{-4}
C2	1.751×10^{-5}	1.100×10^{-5}
C3	-1.811×10^{-8}	1.337×10^{-9}

(6) Calculate the density of oil at the wellhead,

$$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right),$$

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using the following equation with the value of the oil API gravity, γo, at the well site:

$$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right) = \frac{141.5}{\gamma_o + 131.5} \times 62.4$$

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(7) Calculate the density of oil at bottom hole conditions,

$$\rho_{BH}\left(\frac{lbm}{cu\ ft}\right),$$

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using the following equation with: the dissolved GOR, Rs (scf/ STBO), calculated in paragraph (b)(4) of this section; the oil formation volume factor, Bo (bbl/ STBO), calculated in paragraph (b)(5) of this section; the oil density at the wellhead,

$$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right),$$

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calculated in paragraph (b)(6) of this section; and the dissolved gas gravity, $\gamma_{gd} = 0.77$:

$$\rho_{BH}\left(\frac{lbm}{cu\ ft}\right) = \frac{\rho_{WH} + 0.0136 \times Rs \times \gamma_{gd}}{Bo}$$

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(8) Calculate the density of oil in the well,

$$\rho_o\left(\frac{lbm}{cu\ ft}\right),$$

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using the following equation with the density of oil at the wellhead,

$$\rho_{WH}\left(\frac{lbm}{cu\ ft}\right),$$

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calculated in paragraph (b)(6) of this section; and the density of oil at bottom hole conditions,

$$\rho_{BH}\left(\frac{lbm}{cu\ ft}\right),$$

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calculated in paragraph (b)(7) of this section:

$$\rho_o\left(\frac{lbm}{cu\ ft}\right) = 0.5 \times (\rho_{WH} + \rho_{BH})$$

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(9) Calculate the oil flow rate, q_o (*cu ft/sec,*) using the following equation with: the oil formation volume factor, *Bo* (bbl/ STBO), as calculated in paragraph (b)(5) of this section; and the estimated oil production rate at the well head, *Qo* (STBO/ day):

$$q_o\left(\frac{cu\ ft}{sec}\right) = Qo\left(\frac{STBO}{day}\right) \times Bo\left(\frac{bbl}{STBO}\right) \times 5.614\left(\frac{cu\ ft}{bbl}\right) \times \frac{1}{24 \times 60 \times 60}\left(\frac{day}{sec}\right)$$

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(10) Calculate the critical pressure, P_c (psia), and critical temperature, T_c (R), using the equations below with: Gas gravity at standard conditions (pressure, $P = 14.7$ (*psia*), temperature,

T = 60 (F)), $\gamma = 0.75$; and where the mole fractions of nitrogen, carbon dioxide and hydrogen sulfide in the gas are $X_{N2} = 0.168225$, $X_{CO2} = 0.013163$, and $X_{H2S} = 0.013680$, respectively:

$P_c(psia) = 678 - 50 \cdot (\gamma_g - 0.5) - 206.7 \cdot X_{N2} + 440 \cdot X_{CO2} + 606.7 \cdot X_{H2S}$

$T_c(R) = 326 + 315.7 \cdot (\gamma_g - 0.5) - 240 \cdot X_{N2} - 88.3 \cdot X\mathrm{CO}_2 + 133.3 \cdot X_{H2S}$

(11) Calculate reduced pressure, P_r, and reduced temperature, T_r, using the following equations with: the bottom hole pressure, P_{BH}, as determined in paragraph (b)(1) of this section; the bottom hole temperature, T_{BH} (F), as determined in paragraph (b)(2) of this section in the following equations:

$$P_r = \frac{P_{BH}}{P_c}$$

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$$T_r = \frac{T_{BH} + 460}{T_c}$$

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(12)(i) Calculate the gas compressibility factor, Z, using the following equation with the reduced pressure, P_r, calculated in paragraph (b)(11) of this section:

$$z = A + \frac{(1 - A)}{e^B} + C \cdot p_r^D$$

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(ii) The values for A, B, C, D in the above equation, are calculated using the following equations with the reduced pressure, P_r, and reduced temperature, T_r, calculated in paragraph (b)(11) of this section:

$$A = 1.39 \cdot (T_r - 0.92)^{0.5} - 0.36 \cdot T_r - 0.101$$

$$B = (0.62 - 0.23 \cdot T_r) \cdot P_r + \left(\frac{0.066}{(T_r - 0.86)} - 0.037\right) \cdot P_r^2 + \frac{0.32}{10^{9(T_r - 1)}} \cdot P_r^6$$

$$C = (0.132 - 0.32 \cdot \log(T_r))$$

$$D = 10^{0.3106 - 0.49T_r + 0.1824T_r^2}$$

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(13) Calculate the gas formation volume factor,

$$B_g\left(\frac{cuft}{scf}\right),$$

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using the bottom hole pressure, P_{BH} *(psia)*, as determined in paragraph (b)(1) of this section; and the bottom hole temperature, T_{BH} *(F)*, as determined in paragraph (b)(2) of this section:

$$B_g\left(\frac{cuft}{scf}\right) = 0.0283 \cdot \frac{Z \cdot (T_{BH} + 460)}{P_{BH}}()$$

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(14) Calculate the gas flow rate,

$$q_g\left(\frac{cuft}{sec}\right),$$

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using the following equation with: the value of gas formation volume factor,

$$B_g\left(\frac{cuft}{scf}\right),$$

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calculated in paragraph (b)(13) of this section; the estimated gas production rate, Qg (scf/ day); the estimated oil production rate, Qo (STBO/ day); and the dissolved GOR, Rs (scf/ STBO), as calculated in paragraph (b)(4) of this section:

$$q_g\left(\frac{cf}{sec}\right) = (Q_g - R_s \cdot Q_o) \cdot B_g \cdot \frac{1}{24x60x60}$$

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(15) Calculate the flow rate of water in the well, q_w (*cu ft/sec*), using the following equation with the water production rate Qw (bbl/day) at the well site:

$$q_w\left(\frac{cf}{sec}\right) = Qw\left(\frac{bbl}{day}\right) \times 5.614\left(\frac{cf}{bbl}\right) \times \frac{1}{24 \times 60 \times 60}\left(\frac{day}{sec}\right)$$

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§§60.5433a-60.5499a [Reserved]

Table 1 to Subpart OOOOa of Part 60—Required Minimum Initial SO_2 Emission Reduction Efficiency (Z_i)

H_2S content of acid gas (Y), %	**Sulfur feed rate (X), LT/D**			
	2.0 < X < 5.0	**5.0 < X < 15.0**	**15.0 < X < 300.0**	**X > 300.0**
Y > 50	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller.		
20 < Y < 50	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller		97.9
10 < Y < 20	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 93.5, whichever is smaller	93.5	93.5
Y < 10	79.0	79.0	79.0	79.0

Table 2 to Subpart OOOOa of Part 60—Required Minimum SO_2 Emission Reduction Efficiency (Z_c)

	Sulfur feed rate (X), LT/D

H_2S content of acid gas (Y), %	**2.0 < X < 5.0**	**5.0 < X < 15.0**	**15.0 < X < 300.0**	**X > 300.0**
Y > 50	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller.		
20 < Y < 50	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 97.5, whichever is smaller		97.5
10 < Y < 20	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller	90.8	90.8
Y < 10	74.0	74.0	74.0	74.0

X = The sulfur feed rate from the sweetening unit (*i.e.,* the H_2S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H_2S (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide (SO_2) emission reduction efficiency, expressed as percent carried to one decimal place. Z_i refers to the reduction efficiency required at the initial performance test. Z_c refers to the reduction efficiency required on a continuous basis after compliance with Z_i has been demonstrated.

As stated in §60.5425a, you must comply with the following applicable General Provisions:

Table 3 to Subpart OOOOa of Part 60—Applicability of General Provisions to Subpart OOOOa

General provisions citation	**Subject of citation**	**Applies to subpart?**	**Explanation**

§60.1	General applicability of the General Provisions	Yes	
§60.2	Definitions	Yes	Additional terms defined in §60.5430a.
§60.3	Units and abbreviations	Yes	
§60.4	Address	Yes	
§60.5	Determination of construction or modification	Yes	
§60.6	Review of plans	Yes	
§60.7	Notification and record keeping	Yes	Except that §60.7 only applies as specified in §60.5420a(a).
§60.8	Performance tests	Yes	Performance testing is required for control devices used on storage vessels, centrifugal compressors, and pneumatic pumps, except that performance testing is not required for a control device used solely on pneumatic pump(s).
§60.9	Availability of information	Yes	

§60.10	State authority	Yes	
§60.11	Compliance with standards and maintenance requirements	No	Requirements are specified in subpart OOOOa.
§60.12	Circumvention	Yes	
§60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.
§60.14	Modification	Yes	To the extent any provision in §60.14 conflicts with specific provisions in subpart OOOOa, it is superseded by subpart OOOOa provisions.
§60.15	Reconstruction	Yes	Except that §60.15(d) does not apply to wells, pneumatic controllers, pneumatic pumps, centrifugal compressors, reciprocating compressors, storage vessels, or the collection of fugitive emissions components at a well site or the collection of fugitive emissions components at a compressor station.
§60.16	Priority list	Yes	
§60.17	Incorporations by reference	Yes	

§60.18	General control device and work practice requirements	Yes	
§60.19	General notification and reporting requirement	Yes	

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

Background Technical Support Document for the
Proposed Reconsideration of the New Source Performance Standards
40 CFR Part 60, subpart OOOOa

May 2018

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ACRONYMS AND ABBREVIATIONS

Acronyms/Abbreviations	Description
AEO	Annual Energy Outlook
bbl	barrel
boe	Barrels of oil equivalent
BSER	best system of emission reduction
EPA	Environmental Protection Agency
GHG	greenhouse gas
GOR	gas to oil ratio
LDAR	leak detection and repair
Mcf	thousand cubic feet
NSPS	New Source Performance Standards
OEL	open-ended line
OGI	optical gas imaging
PE	professional engineer
PRV	pressure relief valve
scf	standard cubic feet
SOCMI	Synthetic Organic Chemical Manufacturing Industry
tpy	tons per year
TOC	total organic compounds
TSD	Technical Support Document
VOC	volatile organic compounds
VRU	Vapor recovery unit

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1.0 INTRODUCTION

This background technical support document (TSD) provides information relevant to the proposed reconsideration of the Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources ("2016 NSPS OOOOa"). This TSD is presented in two volumes; Volume 1 provides the unit-level analysis supporting the determination of the best system of emission reduction (BSER); and Volume 2 presents the national impacts of the regulatory decisions for the proposed reconsideration.

1.1 Volume 1 - Unit-Level BSER Analysis

The proposed reconsideration only proposes updates to the BSER analysis for fugitive emissions requirements at well sites and compressor stations. Chapter 2 presents detailed information and analyses pertaining to these proposed requirements, including emission data and discussions of available control options and their costs that were considered in the development of standards reflecting the BSER for these emission sources.

1.2 Volume 2 - National Level Impacts

Chapters 3 and 4 present the estimates of national level impacts needed to inform the preamble of the proposed rule and the Regulatory Impact Analysis (RIA) for this proposal, as required under Executive Order 12866. In this volume, we focus on the proposed amendments that result in a change in cost or emissions compared to an updated baseline. The relevant provisions include the fugitive emission requirements and professional engineer certifications for pneumatic pumps and closed vent systems.

It is important to note that national impacts estimates incorporate in to the baseline the fact that some states already have requirements of emissions sources addressed by this proposed rule. Further, this analysis is separate and apart from the analysis required to identify the BSER, which establishes the requirements under section 111(b) of the Clean Air Act (CAA).

1.3 Supporting Documentation

This action follows the development of several prior oil and gas NSPS related actions. This review references several documents that were published as a consequence of these prior actions. For ease of presentation, the following documents are consistently cited in the following sections:

- The gas composition memo that was developed during the NSPS process which characterizes and analyzes data to determine the gas composition and develop ratios for natural gas composition to be used for the various segments in the development of regulations for the oil and natural gas

sector. This document will be referred to as "2011 Gas Composition Memorandum".[1]

- Emissions information and equipment counts for various emission sources were developed from data used to calculate national emissions in the Inventory of U.S. Greenhouse Gas Emissions and Sinks, which incorporates facility-level data submitted to the Greenhouse Gas Reporting Program (GHGRP).[2,3] The most recent available data from the GHG Inventory at the time of the development of this analysis was for 2016, and was used for various portions of the analysis. For the purposes of this document these data sources are referred to as "GHG Inventory" and "GHGRP". The most recent available GHG Inventory covers data from 1990-2016 and currently available GHGRP data cover 2011-2016. These new emissions and activity data have been reviewed for the proposed reconsideration and incorporated into this analysis.
- The TSD for the 2015 NSPS proposal, published in August, 2015, will be referred to in this document as "2015 NSPS Proposal TSD".[4]
- The TSD for the 2016 final NSPS standards, published in May, 2016, will be referred to in this document as "2016 NSPS Final TSD".[5]

All of the calculations supporting the analyses in this document are included in the docket in the form of spreadsheets that are labeled corresponding to the section of this TSD.

[1] Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. "Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking". July 2011. Docket ID No. EPA-HQ-OAR-2010-0505-0084.
[2] EPA 2018. Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016. Available at: https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks.
[3] EPA 2017. Greenhouse Gas Reporting Program. Data reported as of August 5, 2017. Available at: https://www.epa.gov/ghgreporting.
[4] Docket ID No. EPA-HQ-OAR-2010-0505-5021
[5] Docket ID No. EPA-HQ-OAR-2010-0505-7631

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VOLUME 1: UNIT LEVEL BSER ANALYSIS

2.0 FUGITIVE EMISSIONS STANDARDS

Fugitive emissions from components located at well sites and compressor stations are a source of methane and volatile organic compound (VOC) emissions. This chapter explains the causes for these fugitive emissions, provides estimates of methane and VOC emissions for "model" facilities, and provides estimates of nationwide fugitive emissions for new sources in the production, transmission, and storage segments of the crude oil and natural gas source category. Programs that are designed to reduce fugitive emissions are explained in this chapter, as well as estimated costs, estimated emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for fugitive emissions from major production and processing equipment located at well sites and equipment located at compressor stations.

2.1 Fugitive Emissions Description

There are several potential sources of fugitive emissions throughout the oil and natural gas source category. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure and mechanical stresses can also cause components or equipment to emit fugitive emissions. Poor maintenance or operating practices, such as improperly reseated pressure relief valves (PRVs) or worn gaskets on thief hatches on controlled storage vessels are also potential causes of fugitive emissions. Additional sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices such as PRVs, pump seals, valves or controlled liquid storage tanks. These fugitive emissions do not include devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pneumatic pumps, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission.

As discussed in section 2.2, the 2016 NSPS OOOOa promulgated fugitive emissions standards for well sites and compressor stations in addition to the previously promulgated equipment leak standards for onshore natural gas processing plants.[6] In order to differentiate which components and equipment were subject to these standards, the EPA included a separate definition for "fugitive

[6] The Oil and Natural Gas Sector NSPS (40 CFR part 60, subpart OOOO) specifically defines "equipment" relative to standards for equipment leaks of VOC from onshore natural gas processing plants. As used in this chapter, the term "equipment" is used in a broader context and is not meant to be limited by the manner in which the term is currently used in subpart OOOO.

emissions component". Specifically, the 2016 NSPS OOOOa defined fugitive emissions component as follows:

> *Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411a, thief hatches or other openings on a controlled storage vessel not subject to §60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.*

The EPA received feedback through petitions for reconsideration and discussions with various stakeholders that additional changes to the definition may be applicable. One petitioner asserted that the "including but not limited to" description adds uncertainty to what should be included in the collection of fugitive emissions components. Additionally, one petitioner asserted that "compressors" should not be included in the list of fugitive emissions components because they are subject to separate standards as affected facilities within other sections of the 2016 NSPS OOOOa. The EPA is proposing to revise the definition of fugitive emissions component in this reconsideration to remove the terms "including but not limited to" because we recognized the uncertainty when we finalized the 2016 NSPS OOOOa, but is not removing the term compressor from the list of fugitive emissions components. While centrifugal and reciprocating compressors are affected facilities subject to standards, the potential for fugitive emissions remains for compressors. Additionally, the requirements found in 40 CFR 60.5380a or 60.5385a for centrifugal or reciprocating compressors, respectively, are not applicable to compressors located at a well site.

2.2 Fugitive Emissions Requirements in 2016 NSPS OOOOa

On June 3, 2016, the EPA promulgated fugitive emissions standards for well sites and compressor stations at 40 CFR part 60, subpart OOOOa (2016 NSPS OOOOa). These standards required a fugitive emissions monitoring and repair program, where well sites and compressor stations must be monitored semiannually and quarterly, respectively. New, reconstructed, or modified well sites and compressor stations are required to perform an initial monitoring survey within 60 days of the startup of

production (for well sites) or startup of the compressor station. Owners and operators are required to perform monitoring using optical gas imaging (OGI), where any visible image is defined as a fugitive emission and must be repaired within 30 days of detection and resurveyed within 30 days of repair in order to verify successful repair. As an alternative, Method 21 of Appendix A-7 to Part 60 ("Method 21") may be used to identify fugitive emissions, where an instrument reading of 500 parts per million (ppm) or greater is considered a fugitive emission. Each owner or operator is required to develop and implement a fugitive emissions monitoring plan that includes site-specific information, such as a site map and observation path taken to ensure line of sight for each fugitive emissions component during the monitoring survey, in addition to specifying how the survey will be conducted (*i.e.*, which monitoring instrument will be used, how operator-specified parameters such as viewing distance will be established, and other parameters as defined in the 2016 NSPS OOOOa).

In March 2018, the EPA amended the fugitive emissions standards by removing the requirement that repairs which have been delayed beyond the 30-day deadline are completed during the next unplanned or emergency shutdown or vent blowdown and by establishing separate monitoring requirements for well sites located on the Alaskan North Slope. These amended standards for well sites located on the Alaskan North Slope specify that new well sites that startup production between September and March must conduct initial monitoring within 6 months of the startup of production[7] or by June 30, whichever is later, while well sites that startup production between April and August must comply with the 60-day initial monitoring requirement in the 2016 NSPS OOOOa. Similarly, well sites that are modified between September and March must conduct initial monitoring within 6 months of the first day of production for each collection of fugitive emissions components or by June 30, whichever is later. Further, all well sites located on the Alaskan North Slope that are subject to the fugitive emissions requirements must conduct annual monitoring, instead of the semiannual monitoring required for other well sites. Subsequent annual monitoring must be conducted at least 9 months apart.

2.3 Fugitive Emissions Data and Emissions Factors

2.3.1 Model Plants

The number and type of fugitive emissions components located at well sites and compressor stations can consist of a large variety of combinations of process equipment and other components. This is particularly true for well sites where oil and natural gas production practices and equipment vary from

[7] Startup of production is defined in 40 CFR 60.5430a.

site-to-site. Some production sites may include only a single wellhead that is extracting oil or natural gas from the ground, while other sites may include multiple wellheads attached to a well pad. A well site is a site where the production, extraction, recovery, lifting, stabilization, separation and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components that may be sources of fugitive emissions. A well site can serve one well on a pad or multiple wells on a pad. Therefore, the number of components with potential for fugitive emissions can vary depending on the number of wells and the number of major production and processing equipment at the site. Model plants were developed to analyze potential options for the control of fugitive emissions at well sites and compressor stations.

Information related to the fugitive emissions component counts was obtained from the GRI/EPA natural gas industry study,[8] the EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks for 2016, and the EPA's GHG Mandatory Reporting Rule (40 CFR part 98, subpart W). The GRI/EPA document provided average fugitive emissions component counts for the natural gas production, natural gas processing, natural gas transmission, and natural gas storage sectors, including counts for valves, connectors, OELs, and PRVs. Although these counts do not include all potential fugitive emissions components, as described in the definition of "fugitive emissions component," these remain the best available data.

In the 2016 NSPS Final TSD, we developed three subtypes of well site model plants: (1) gas well site, (2) oil well site with a gas to oil ratio (GOR) of less than 300 scf of gas per stock tank barrel ("GOR<300"), and (3) oil well site with GOR greater than 300 scf of gas per stock tank barrel ("GOR > 300"). However, because additional data regarding low production well sites (*i.e.,* well sites where the average combined oil and natural gas production is less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) is now available, we have subcategorized well sites by production for this proposed reconsideration. Thus, we have developed the following model plant well sites for (1) non-low production sites and (2) low production sites: (a) gas well site, (b) oil well site with GOR <300, and (c) oil well site with GOR >300. In the 2016 NSPS Final TSD, we also developed three subtypes of compressor station model plants: (1) gathering and boosting stations, (2) transmission stations, and (3) storage stations. The following sections discuss the revisions to the non-low production

[8] Gas Research Institute (GRI)/U.S. EPA. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. June 1996 (EPA-600/R-96-080h).

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model plants, development of the low production model plants, and revisions to the compressor station model plants.

2.3.2 Non-low Production Well Site Model Plant Development

For each non-low production well site model plant, we estimated the average number of wells associated with a well site using data from the DrillingInfo HPDI® database.[9] The national average of wells per well site was 1.81, which was rounded to 2.0 wells per well site for each non-low production model plant. The reported equipment counts for each non-low production well site subtype in the GHG Inventory were used to determine the average major production and processing equipment counts per well. These average equipment counts per well were multiplied by the average number of wells at a well site (2) and then rounded up to the nearest integer, consistent with the analysis in the 2016 NSPS Final TSD. The specific types of major production and processing equipment included in the non-low production model well sites include: wellheads, separators, meters/piping, in-line heaters, dehydrators, and storage vessels. The types of fugitive emissions components associated with these production equipment types include: valves, connectors, OELs, PRVs, and thief hatches. Except for storage vessel thief hatches, component counts for each type of production equipment were calculated using the average component counts for onshore production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI report. Fractions of components were rounded up to the nearest integer. It was assumed that each well site has at least 1 storage vessel subject to fugitive emissions requirements, and that each storage vessel contains 1 thief hatch.

Fugitive emissions from storage vessels were not previously considered in the well site model plants because only a limited universe of storage vessels would be subject to the fugitive emissions requirements. Specifically, storage vessels that have the potential to emit 6 tons per year (tpy) or more of VOC are considered affected facilities and subject to the control requirements for storage vessels in 40 CFR 60.5395a. In calculating the potential emissions, owners and operators can take into account emission limits in practically and legally enforceable permits. Therefore, there can be a universe of controlled storage vessels that are not subject to the control requirements in the 2016 NSPS OOOOa for affected facility storage vessels. These controlled storage vessels are then subject to the fugitive emissions requirements if they are located at a well site or compressor station that is subject to the fugitive emissions requirements. In evaluating appropriate monitoring frequencies for fugitive emissions components, the EPA considered data indicating that leak rates from storage vessels may be much

[9] Drilling Information, Inc. 2014. *DI Desktop.* 2014 Production Information Database.

higher than those for other fugitive components and that many operators may be claiming many of their storage vessels as being subject to the fugitives monitoring program rather than affected facilities subject to the 2016 NSPS OOOOa control requirements for storage vessels found in 40 CFR 60.5395a.

The EPA has observed extensive leak rates from storage vessels at oil and natural gas production well pads through inspection efforts in many locations, including Colorado, Ohio, and Texas. As an example, in 2012 inspectors from the EPA and the Colorado Department of Public Health and Environment (CDPHE) observed emissions using OGI from storage vessels in tank batteries receiving production from 119 of 177 wells (or 63 of 99 inspected tank batteries). Potential causes of storage vessel emissions include inadequate design, operation, or maintenance. To address these potential causes, the EPA and CDPHE lodged a settlement with Noble Energy, Inc. (Noble) in April 2015.

Since that time, the EPA has received extensive reports from Noble pursuant to the settlement agreement that provide updates as to settlement implementation. The settlement included a requirement to perform an engineering evaluation to ensure adequate design for each tank battery. The engineering evaluation deadlines were staggered with tank batteries placed into one of five groups, each with a different deadline. The final deadline was July 1, 2017. After each deadline, the EPA receives a "Certification of Completion Report" that lists the tank systems for which Noble has completed its engineering evaluation. The EPA also receives an "End of Phase Report," which includes a list of emissions observed from storage vessels from the date the engineering evaluation was completed for a tank system through the end of that reporting period (typically around 5-11 months). These End of Phase Reports are reviewed by EPA and CDPHE and then posted to Noble's website at noblecolorado.com. Finally, the EPA receives semi-annual reports that list instances of emissions from storage vessels during that six-month reporting period. To better understand storage vessel leak rates, excluding design issues, the EPA looked at these reports to ascertain what portion of tank batteries had one or more storage vessel leaks in the period between completion of the engineering evaluation and the end of the relevant reporting period (End of Phase Reports for tank batteries in Groups I through III and semi-annual reporting period for tank batteries greater than 50 tpy actual uncontrolled emissions or in the cross-section sampling analysis group). A total of 621 tank batteries were certified in those five groups' Certification of Completion Reports. Approximately 40% of those had one or more storage vessel leaks detected with OGI during the 5-26 months of monitoring before the end of the relevant reporting

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period.[10] Note that the OGI monitoring frequency required by the Noble settlement ranges from monthly down to no OGI monitoring, depending on the tank battery, so not all tank batteries were necessarily monitored during the period in question but some tank batteries were monitored many times. Based on EPA inspection results in various basins and analysis of Noble's post-design analysis inspection data, the EPA believes that leak rates for storage vessels are much higher than those for other fugitive components at well pads.

Inspection data and compliance reports for the 2016 NSPS OOOOa indicate that many operators determined that few or no storage vessels are affected facilities under the 2016 NSPS OOOOa. For example, review of the 2016 NSPS OOOOa compliance reports indicates that some operators may be incorrectly averaging emissions across storage tanks in tank batteries when determining the potential for VOC emissions. Both the 2012 NSPS OOOO and 2016 NSPS OOOOa specify that a storage vessel affected facility is "a single storage vessel" that "has the potential for VOC emissions equal to or greater than 6 tpy." 40 CFR 60.5365(e) and 60.5365a(e). In prior rulemakings, the EPA explained that storage vessel emission estimation methods for the potential for VOC emissions generally require information on both the composition and volumetric rate of the liquid entering the storage vessel, where the volumetric throughput is frequently calculated by recording the volume of liquid collected from the receiving vessel(s) over time. 79 FR 79026. Because the 2012 NSPS OOOO and 2016 NSPS OOOOa define the affected facility as "a single storage vessel," the determination of the potential for VOC emissions must be based on the liquid throughput of each "single storage vessel," even where the storage vessel is part of a tank battery. Operators should ensure that the determination of the potential for VOC emissions reflects each storage vessel's actual configuration and operational characteristics. Furthermore, if a storage vessel's configuration or operational characteristics are intended to avoid the 2012 NSPS OOOO or 2016 NSPS OOOOa applicability, the NSPS General Provisions on circumvention at 40 CFR 60.12 may provide grounds for state or federal enforcement. Similarly, the EPA notes that affected facility determinations are allowed to account for legally and practically enforceable limits in determining the potential for VOC emissions for a storage vessel. However, 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. Given the potential for recurring emissions from controlled

[10] Memorandum from Virginia Sorrell, EPA to Apple Chapman and Phil Brooks, EPA, *Analysis of Consent Decree Reports from Noble Energy, Inc. as to Emissions Observations from Thief Hatches or Other Openings on Controlled Storage Vessels; Oil and Natural Gas Sector: Emission Standards for New, Reconstructed and Modified Sources Reconsideration – SAN 5719.8* located at Docket ID No. EPA-HQ-OAR-2017-0483.

storage vessel thief hatches or other opening owing to operation and maintenance performance even where adequate design has been verified, any limit on capture and control efficiency from storage vessels must include sufficient monitoring to timely identify and repair emissions from storage vessels to ensure the limit on capture and control efficiency is consistently achieved.

Where a storage vessel is part of a tank battery, some operators appear to derive the maximum daily throughput of a storage vessel in a battery by using the throughput to the entire battery (by using records of liquids collected from the battery over time) and dividing that figure by the number of storage vessels in the battery. This approach for determining a storage vessel's maximum daily throughput is incorrect for certain operational configurations. For instance, where a tank battery is operated such that all pressurized liquids from the separator initially flow to only one storage vessel, and then overflow to the next, and so on (*i.e.*, in series or series flow), the first individual storage vessel's throughput would be the entire battery's throughput, not the entire battery's throughput apportioned evenly among the storage vessels. Dividing an entire battery's throughput by the number of storage vessels in the battery would greatly underestimate flash emissions from the first storage vessel connected in series, which is where liquid pressure drops from separator pressure to atmospheric pressure. However, such division could be appropriate where all liquids flow through a splitter system in a common header that ensures that all liquids initially flow in equal amounts to all storage vessels in a tank battery at all times since the liquid pressure drop would occur equally in each storage vessel in the battery.

In summary, in proposing these revisions to the 2016 NSPS OOOOa, the EPA concluded that the higher potential frequency and magnitude of storage vessel emissions will typically be addressed through the requirements for storage vessel affected facilities rather than through the fugitives monitoring requirements where operators correctly determine potential for VOC emissions for individual storage vessels. Additionally, the EPA notes that affected facility determinations are allowed to account for legally and practically enforceable limits in determining the potential for VOC emissions for a storage vessel. However, 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 terms and conditions such that the source cannot lawfully exceed the limit. Given the potential for recurring emissions from storage vessels owing to operation and maintenance performance even where adequate design has been verified, any limit on capture and control efficiency from storage vessels must include sufficient monitoring to timely identify and repair storage vessel leaks such that the limit on capture and control efficiency is consistently achieved. In such cases, the legally and practically enforceable limit would be providing storage vessel monitoring requirements to address the higher potential frequency and

magnitude of storage vessel emissions and any monitoring through the 2016 NSPS OOOOa fugitives monitoring program would be secondary. In light of the above, it is estimated that 1 controlled storage vessel will be subject to the fugitive emissions requirements at each well site for purposes of development of the revised model plants.

A summary of the fugitive emissions component counts for the non-low production model plants is presented in Table 2-1 for non-low production. Specific changes from the 2016 NSPS OOOOa model plants include the following:

- Reduced the number of meter/piping from 3 to 2 for gas well sites and oil well sites with GOR >300, and
- Added 1 controlled storage vessel thief hatch to each of the non-low production model plants.

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Table 2-1. Average Fugitive Emissions Component Count for Non-Low Production Well Site Model Plants

Production Equipment	Model Plant Equipment Counts	Average Component Count Per Unit of Model Plant[a]				
		Valves	Connectors	OELs	PRVs	Thief Hatches
Non-Low Production Natural Gas Well Site Model Plant						
Wellheads	2	19.0	74.0	2.0	0.0	--
Separators	2	43.0	137.0	8.0	3.0	--
Meters/Piping	2	26.0	96.0	1	1.0	--
In-Line Heaters	1	14.0	65.0	2.0	1.0	--
Dehydrators	1	24.0	90.0	2.0	2.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	127.0	462.0	14.0	7.0	1.0
Non-Low Production Oil Well Site (<300 GOR) Model Plant						
Wellheads	2	10.0	8.0	0.0	2.0	--
Separators	1	6.0	10.0	0.0	0.0	--
Headers	1	5.0	4.0	0.0	0.0	--
Heater/Treaters	1	8.0	20.0	0.0	0.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	29.0	42.0	0.0	2.0	1.0
Non-Low Production Oil with Associated Gas Well Site (>300 GOR) Model Plant						
Wellheads	2	10.0	8.0	0.0	2.0	--
Separators	1	6.0	10.0	0.0	0.0	--
Meters/Piping	2	26	96	1.0	1.0	--
Headers	1	5.0	4.0	0.0	0.0	--
Heater/Treaters	1	8.0	20.0	0.0	0.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	55.0	138.0	1.0	3.0	1.0

a. Data Source for average component count per equipment type: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h). Values were multiplied by the rounded equipment count for model plant component counts.

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2.3.2 Low Production Well Site Model Plant Development

We created new model plants for well sites that have low production, where the average combined oil and natural gas production is less than 15 boe per day averaged over the first 30 days of production. Following promulgation of the 2016 NSPS OOOOa, information was received which contained component level emissions information for well sites in the Dallas/Fort Worth area (herein referred to as the "Fort Worth Study").[11] As part of the Fort Worth Study, total counts were provided for the number of wells, valves, connectors, storage vessels, compressors, separators, dehydrators, and other miscellaneous equipment, such as meter stations and heaters. Given the characteristics of the basin where these well sites are located, this information was only available for natural gas wells, including both dry and wet gas. We used the average count of major production and processing equipment that was reported for the 27 low production well sites as the basis for the natural gas well model plant for low production well sites. Because the fugitive emissions component counts were not available for each individual piece of major production and processing equipment, we used the average fugitive emissions component counts per major production and processing equipment obtained from the 1996 EPA/GRI Study.[12]

To create model plants for low production oil wells with <300 GOR and oil wells with associated gas (>300 GOR), we determined the difference between the non-low production and low production natural gas well site model plant fugitive emissions component counts, by dividing the component counts for the low production natural gas well sites by the component counts for the non-low production natural gas well sites. This scaling factor was applied to the non-low production oil and oil with associated gas well site model plants to create low production model plants for these types of well sites.

Additionally, consistent with the information presented in section 2.3.1, we included 1 controlled storage vessel per low production model plant and 2 wells per model plant. Therefore, the main difference between the non-low production and low production model plants is realized in the number of major production and processing equipment, other than controlled storage vessels. Table 2-2 includes the average fugitive emissions component counts for the low production well site model plants.

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[11] "The Natural Gas Air Quality Study (Final Report)", prepared by Eastern Research Group, Inc. July 13, 2011, available at *http://fortworthtexas.gov/gaswells/air-quality-study/final/*.

[12] The average fugitive emissions components per major production and processing equipment were calculated by summing the total quantity of equipment and dividing by the total number of sites for both Eastern & Western U.S. EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h).

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Table 2-2. Average Fugitive Emissions Component Count for Low Production Well Site Model Plants

Production Equipment	Model Plant Equipment Counts	Average Component Count Per Unit of Model Plant[a]				
		Valves	Connectors	OELs	PRVs	Thief Hatches
Low Production Natural Gas Well Site Model Plant						
Wellheads	2	19.0	74.0	2.0	0.0	--
Separators	2	43.0	137.0	8.0	3.0	--
Meters/Piping	1	13.0	48.0	1.0	0.5	--
In-Line Heaters	0	0.0	0.0	0.0	0.0	--
Dehydrators	1	24.0	90.0	2.0	2.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	100.0	349.0	12.0	5.0	1.0
Low Production Oil Well Site (<300 GOR) Model Plant						
Wellheads	2	8.0	6.0	0.0	2.0	--
Separators	1	5.0	8.0	0.0	0.0	--
Headers	1	4.0	3.0	0.0	0.0	--
Heater/Treaters	1	6.0	15.0	0.0	0.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	23.0	32.0	0.0	2.0	1.0
Low Production Oil with Associated Gas Well Site (>300 GOR) Model Plant						
Wellheads	2	8.0	6.0	0.0	1.0	--
Separators	1	5.0	8.0	0.0	0.0	--
Meters/Piping	2	20.0	72.0	1.0	1.0	--
Headers	1	4.0	3.0	0.0	0.0	--
Heater/Treaters	1	6.0	15.0	0.0	0.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	44.0	105.0	1.0	3.0	1.0

a. Data Source for average component count per equipment type: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h). Values were multiplied by the rounded equipment count for model plant component counts.

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2.3.3 Wellhead Only Model Plant Development

We created model plants that consist of wellheads and no major production or processing equipment, for each of the 3 sub-types of well site model plants (*i.e.,* gas well, oil well, and oil with associated gas well sites). Each of these sub-types contain 2 wellheads each. We did not separate these by non-low production or low production because we assume the same number of wellheads for these well sites, regardless of production. The associated fugitive emissions components for these wellheads are summarized in Table 2-3.

Table 2-3. Average Fugitive Emissions Component Count for Wellhead Only Well Site Model Plants

Production Equipment	Model Plant Equipment Counts	Average Component Count Per Unit of Model Plant[a]				
		Valves	Connectors	OELs	PRVs	Thief Hatches
Natural Gas Well Site Model Plant						
Wellheads	2	19	74	2	0	0
Oil Well Site (<300 GOR) Model Plant						
Wellheads	2	10	8	0	2	0
Oil with Associated Gas Well Site (>300 GOR) Model Plant						
Wellheads	2	10	8	0	2	0

a. Data Source for average component count per equipment type: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h). Values were multiplied by the rounded equipment count for model plant component counts.

2.3.4 Compressor Station Model Plant Development

The 2016 NSPS OOOOa Final TSD evaluated fugitive monitoring at three types of compressor stations; gathering and boosting stations, transmission stations, and storage stations. The equipment associated with these compressor stations vary depending on the volume of natural gas that is transported and whether any treatment of the gas, such as the removal of water or hydrocarbons occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components (*e.g.,* valves, connectors) that may be sources of fugitive emissions associated with these operations.

Gathering and Boosting Stations. Gathering and boosting stations are sites that collect oil and natural gas from well sites and direct this production fluid to the natural gas processing plant. These stations have similar production and processing equipment (including separators, meters, piping, compressors, in-line heaters, dehydrators, and other equipment) as what is included in the well site model plants; however, these stations are not directly connected to the wellhead. The 1996 EPA/GRI document

does not have specific information on major production and processing equipment counts for the gathering and boosting segment, but it does include fugitive emissions component counts for gathering compressors within the oil and natural gas production data. To estimate the additional major production and processing equipment at a gathering and boosting model plant, the weighted averages of major production and processing equipment counts for the Eastern and Western U.S. data sets for onshore production equipment were calculated. The weighted averages of the data sets were determined to be 11 separators, 7 meters/piping, 5 gathering compressors, 7 in-line heaters, and 5 dehydrators. These average equipment counts were used to create the model plant for gathering and boosting stations. The fugitive emissions components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded because they are affected facilities subject to other standards within the 2016 NSPS OOOOa. Compressor seals are discussed in further details in Chapter 8 of the 2016 Final TSD. A summary are the fugitive emissions component counts for the oil and natural gas gathering and boosting station model plant are presented in Table 2-4. This model plant did not change from the model plant used in the 2016 NSPS OOOOa.

Table 2-4. Average Fugitive Emissions Component Count for Gathering and Boosting Station Model Plants

Production Equipment	Model Plant Equipment Counts	Average Component Count Per Model Plant[a]			
		Valves	Connectors	OELs	PRVs
Gathering and Boosting Stations					
Separators	11	242	748	44	11
Meters/Piping	7	91	336	0	0
Gathering Compressors	5	355	875	15	20
In-Line Heaters	7	98	455	14	7
Dehydrators	5	120	450	10	10
	Rounded Total	906	2,864	83	48

a. Data Source for average component count per equipment type: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h). Values were multiplied by the rounded equipment count for model plant component counts.

Natural Gas Transmission and Storage Station Model Plants. Natural gas transmission and storage stations are facilities that use compressors to move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, transmission stations may include production equipment for liquids separation, natural gas dehydration, and storage vessels for the storage of water and hydrocarbon liquids.

Residue (sales) gas compressors operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment.

The segments include fugitive emissions from fugitive emissions component related to the inlet and outlet pipelines, meter runs, dehydrators, and other piping located at the compressor building for transmission and storage stations, and injection/withdrawal components associated with the injection/withdrawal well piping at storage stations. This industry segment also includes emissions from compressor related components, but does not include emissions from compressor seals or site blowdown open-ended lines. As discussed in the 2016 Final TSD, blowdown open-ended lines were excluded from the analysis because these are considered vents and are not sources of fugitive emissions. Fugitive emissions component counts were obtained from the 1996 EPA/GRI study. A summary of the fugitive emissions component counts is presented in Table 2-5.

Table 2-5. Average Fugitive Emissions Component Count for Natural Gas Transmission and Storage Station Model Plants

Component	Model Plant Component Count[a]	
	Transmission Facility	Storage Facility
Valve	673	1,868
Control Valve	31	--
Connector	3,068	5,571
OEL	51	353
PRV	14	66
Valve (Injection/Withdrawal)	--	30
Connector (Injection/Withdrawal)	--	89
OEL (Injection/Withdrawal)	--	7
PRV (Injection/Withdrawal)	--	1

a. Data Source: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-17 and 4-24, June 1996. (EPA-600/R-96-080h)

2.3.5 Fugitive Emissions Estimation Method

Baseline model plant emissions were calculated using the fugitive emissions component counts from the GHG Inventory, derived from the Greenhouse Gas Reporting Program (GHGRP), 1996 EPA/GRI study, and 40 CFR part 98, subpart W tables as described above, the component oil and natural gas production emission factors from the *Protocol for Equipment Leak Emission Estimates* ("1995

Protocol) as incorporated into AP-42[13] for non-thief hatch fugitive emissions components. The emissions factor used for thief hatches on controlled storage vessels was derived from a study that conducted aerial surveys for emissions at oil and gas production sites located in seven basins across the U.S.[14] In this study, helicopter-based OGI monitoring was performed at 8,220 well sites. A total of 494 fugitive emission sources were identified at 327 sites, averaging approximately 1.5 fugitive sources per site. Fugitive emissions[15] from storage vessels accounted for 92 percent of the total fugitive sources, with 198 fugitive sources associated with storage vessel pressure relief valves (PRVs) and 257 fugitive sources associated with thief hatches. The estimated detection limit for the OGI instrument used by the study was 1 grams per second (g/s) for heavier hydrocarbons and 3 g/s for methane.[16] Based on this information, we used the 1 g/s estimated emission rate in combination with the frequency of storage vessel emissions identified in the study to estimate emissions from thief hatches for purposes of the model plants. Annual emissions were calculated assuming 8,760 hours of operation each year. The emissions factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight rations as described in the 2011 Gas Composition Memorandum developed for the 2012 NSPS.[17] The emission factors presented in Table 2-6 were used to estimate the emissions from well sites, gathering and boosting stations, and natural gas transmission and storage stations. Table 2-7 summarizes the methane emissions factor for each component type in the transmission and storage station model plants. Table 2-8 summarizes the calculated baseline fugitive emissions for each of these model plants.

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[13] U.S. EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)

[14] Lyon, David R., et al., *Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites*. Environmental Science and Technology 2016, 50, 4877-4886.

[15] It was difficult for the Lyon, David R., et al., study to attribute emissions from storage vessels to specific malfunctions or normal operations. The study predicted liquid unloading events and stuck open separator dump valves would contribute less than 0.1% of the emissions detected for each event. The other 99.8% of the storage vessel emissions were not characterized by the study. See *Id.* At pages 4882-4883.

[16] *Id.*

[17] Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. "Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking". July 2011. Docket ID No. EPA-HQ-OAR-2010-0505-0084.

Table 2-6. Oil and Natural Gas Average TOC Emissions Factors

Component Type	Component Service	Uncontrolled Emissions Factor[a] (kg/hr/component)
Valves	Gas	4.5E-03
Flanges	Gas	3.9E-04
Connectors	Gas	2.0E-04
OEL	Gas	2.0E-03
PRV	Gas	8.8E-03
Thief Hatches[b]	--	0.1296

a. Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)
b. Thief hatch emission factors are based on information obtained from Lyon, D., et al. "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," Environ. Sci. Technol. 2016, 50, 4877-4886. We have used 1g/s for emissions from thief hatches and tank vents because the study represents this as the minimum detection limit for these sources which have emissions composed primarily of higher hydrocarbons and adjusted this value to account for the percentage of storage vessels identified with fugitive emissions during the study (3.6%) .

Table 2-7. Oil and Natural Gas Transmission and Storage Average Methane Emissions Factors

Component Type	Component Methane Emissions Factor[a] (Mscf/year/component)
Transmission Facility	
Valves	0.867
Control Valve	8
Connectors	0.147
OEL	11.2
PRV	6.2
Storage Facility	
Valve	0.867
Connector	0.147
OEL	11.2
PRV	6.2
Valve (Injection/Withdrawal)	0.918
Connector (Injection/Withdrawal)	0.125
OEL (Injection/Withdrawal)	0.237
PRV (Injection/Withdrawal)	1.464

a. Data source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Tables 4-17 and 4-24, June 1996. (EPA-600/R-96-080h)

Table 2-8a. Estimated Baseline Fugitive Emissions for the Well Site Model Plants[a]

Model Plant Component Type	Model Plant Component Count	Uncontrolled Emissions Factor[a] (kg/hr/component)	Uncontrolled Emissions (tpy)	
			Methane[b]	VOC[c]
Non-Low Production Gas Well Site				
Valves	127	4.5E-03	3.83	1.06
Flanges	0	3.9E-04	0.00	0.00
Connectors	462	2.0E-04	0.62	0.17
OEL	14	2.0E-03	0.19	0.05
PRV	7	8.8E-03	0.41	0.12
Thief Hatch	1	0.1296	0.87	0.24
		Total	5.91	1.64
Non-Low Production Oil Well Site				
Valves	29	4.5E-03	0.87	0.24
Flanges	54	3.9E-04	0.14	0.04
Connectors	42	2.0E-04	0.06	0.02
OEL	0	2.0E-03	0.00	0.00
PRV	2	8.8E-03	0.12	0.03
Thief Hatch	1	0.1296	0.87	0.24
		Total	2.06	0.57
Non-Low Production Oil w/Associated Gas				
Valves	55	4.5E-03	1.7	0.46
Flanges	54	3.9E-04	0.14	0.04
Connectors	138	2.0E-04	0.19	0.05
OEL	1	2.0E-03	0.01	0.00
PRV	3	8.8E-03	0.18	0.05
Thief Hatch	1	0.1296	0.87	0.24
		Total	3.0	0.85
Low Production Gas Well Site				
Valves	100	4.5E-03	3.01	0.84
Flanges	0	3.9E-04	0.00	0.0
Connectors	349	2.0E-04	0.47	0.13
OEL	12	2.0E-03	0.16	0.05
PRV	5	8.8E-03	0.30	0.08
Thief Hatch	1	0.1296	0.87	0.24
		Total	4.80	1.34
Low Production Oil Well Site				
Valves	23	4.5E-03	0.69	0.19
Flanges	41	3.9E-04	0.11	0.03
Connectors	32	2.0E-04	0.04	0.01
OEL	0	2.0E-03	0.00	0.00
PRV	2	8.8E-03	0.12	0.03
Thief Hatch	1	0.1296	0.87	0.24
		Total	1.83	0.51

Model Plant Component Type	Model Plant Component Count	Uncontrolled Emissions Factor[a] (kg/hr/component)	Uncontrolled Emissions (tpy)	
			Methane[b]	VOC[c]
Low Production Oil Well Site w/Associated Gas				
Valves	44	4.5E-03	1.33	0.37
Control Valves	41	3.9E-04	0.11	0.03
Connectors	105	2.0E-04	0.14	0.04
OEL	1	2.0E-03	0.01	0.00
PRV	3	8.8E-03	0.18	0.05
Thief Hatch	1	0.1296	0.87	0.24
		Total	2.63	0.73
Natural Gas Wellhead Only				
Valves	19	4.5E-03	0.57	0.16
Flanges	0	3.9E-04	0.00	0.00
Connectors	75	2.0E-04	0.10	0.30
OEL	2	2.0E-03	0.03	0.00
PRV	0	8.8E-03	0.00	0.00
		Total	0.7	0.19
Oil Wellhead Only				
Valves	10	4.5E-03	0.3	0.08
Flanges	20	3.9E-04	0.05	0.02
Connectors	8	2.0E-04	0.01	0.00
OEL	0	2.0E-03	0.00	0.00
PRV	2	8.8E-03	0.12	0.03
		Total	0.48	0.13
Oil Well w/Associated Gas Wellhead Only				
Valves	10	4.5E-03	0.3	0.08
Flanges	20	3.9E-04	0.05	0.02
Connectors	8	2.0E-04	0.01	0.00
OEL	0	2.0E-03	0.00	0.00
PRV	2	8.8E-03	0.12	0.03
		Total	0.48	0.13

a. Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017) for TOC emissions factors for components in gas service.
b. Methane emissions calculated using 0.695 weight ratio for methane/TOC for well sites and gathering and boosting obtained from the 2011 Gas Composition Memorandum.
c. VOC emissions calculated using 0.193 weight ratio for methane/TOC for well sites obtained from the 2011 Gas Composition Memorandum.

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Table 2-8b. Estimated Baseline Fugitive Emissions for the Compressor Station Model Plants[a]

Model Plant Component Type	Model Plant Component Count	Uncontrolled Emissions Factor[a]	Uncontrolled Emissions (tpy)	
			Methane[b]	VOC[c]
Gathering and Boosting Station				
		kg/hr/component		
Valves	906	4.5E-03	27.35	7.603
Flanges	0	3.9E-04	0.0	0.0
Connectors	2,864	2.0E-04	3.84	1.07
OEL	83	2.0E-03	1.11	0.31
PRV	48	8.8E-03	2.83	0.79
		Total	35.14	9.77
Transmission Station				
		Mscf/year/component		
Valves	673	0.867	12.1	0.34
Control Valves	31	8	5.2	0.14
Connectors	3,068	0.147	9.4	0.26
OEL	51	11.2	11.9	0.33
PRV	14	6.2	1.8	0.05
		Total	40.4	1.12
Storage Station				
		Mscf/year/component		
Valves	1,868	0.867	33.71	0.93
Connectors	5,571	0.147	17.05	0.47
OEL	353	11.2	82.29	2.28
PRV	66	6.2	8.52	0.24
Valves (Injection/Withdrawal)	30	0.918	0.57	0.02
Connectors (Injection/Withdrawal)	89	0.125	0.23	0.01
OEL (Injection/Withdrawal)	7	0.237	0.03	0.00
PRV (Injection/Withdrawal)	1	1.464	0.03	0.00
		Total	142.4	3.94

a. Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017) for TOC emissions factors for components in gas service.
b. Methane emissions calculated using 0.695 weight ratio for methane/TOC for gathering and boosting obtained from the 2011 Gas Composition Memorandum. Methane emissions for transmission and storage were calculated by multiplying the model plant component count by the component methane emission factor and converting to tons using the conversion factor 0.02082 tons methane/Mscf methane.
c. VOC emissions calculated using 0.193 weight ratio for methane/TOC for gathering and boosting obtained from the 2011 Gas Composition Memorandum. VOC emissions calculated using 0.0277 weight ratio for VOC/methane for transmission and storage obtained from the 2011 Gas Composition Memorandum.

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2.4 Control Techniques

As shown in the 2016 TSD, the EPA has previously evaluated the cost of using OGI or Method 21 for detection of fugitive emissions in its BSER analysis for reducing fugitive emissions at well sites and compressor stations. In the 2016 NSPS OOOOa, the EPA determined OGI to be the BSER but provided Method 21 as an alternative.[18] Based on a review of various state regulations,[19] OGI and Method 21 remain the main detection technologies for identifying fugitive emissions, and none of the petitions for reconsideration identify any specific new detection technologies or control techniques for us to evaluate as BSER. Therefore, for purposes of this reconsideration, we did not evaluate other detection technologies or control techniques. However, we did evaluate the use of OGI and Method 21 at various monitoring frequencies for each of the updated or newly developed model plants. The following sections describe our evaluation of the potential emission reductions and cost of control for a fugitive emissions monitoring and repair program using either OGI or Method 21.

2.4.1 Fugitive Emissions Detection and Repair with OGI

The reduction of fugitive emissions from well sites and compressor stations (*i.e.*, gathering and boosting stations, transmission stations, and storage facilities) involves the development of a fugitive emissions monitoring plan. As described in the proposed reconsideration, the company develops and implements a monitoring plan that covers the collection of fugitive emissions components at well sites or compressor stations within a company defined area. The monitoring plan would include inspection of the collection of all fugitive emissions components, such as valves, connectors, open-ended lines/valves, pressure relief devices, closed vent systems, compressors, and thief hatches on controlled storage vessels. The plan would include provisions to repair or replace fugitive emissions components if evidence of fugitive emissions is discovered during the OGI survey (*e.g.*, any visible emissions from a fugitive emissions component observed using OGI).

In order to estimate the cost of implementation of a monitoring and repair plan, the EPA estimated the cost of repair, which is based on the number of components found to have fugitive emissions. Since OGI visualizes gaseous emissions using active or passive infrared imaging, the OGI operator is not able to determine the exact concentration or emission rate of the fugitive emissions; however, all visualized fugitive emissions are subject to requirements for repair. If a fugitive emissions component cannot be

[18] 81 FR 35846.

[19] See memorandum *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 12, 2018.

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immediately repaired during the monitoring survey, the operator must repair the component as soon as practicable, but no later than 60 days after detection of the fugitive emissions. A first attempt at repair is required within 30 days after detection of the fugitive emissions. Repair is not considered complete until the fugitive emissions component has been resurveyed to verify the repair was successful. For this resurvey, the operator may use OGI, Method 21 or the alternative screening procedures specified in section 8.3.3 of Method 21 to confirm that the component is no longer emitting fugitive emissions. When OGI is used for the resurvey, no visible emissions indicate that the fugitive emissions component has been repaired. When Method 21 is used for the resurvey, no detectable emissions (*e.g.,* a concentration of less than 500 ppm above background) indicate that the fugitive emissions component has been repaired.

2.4.1.2 OGI Emission Reduction Potential

Information in the white paper on oil and natural gas leaks[20] related to the potential emission reductions from OGI monitoring and repair varied from 40 to 99 percent. The data from these studies are based on the gathering of individual OGI surveys at various oil and natural gas segment sites. The variation in the percent reductions from these OGI surveys generally depended on whether large fugitive emission sources were found during the OGI survey and assumptions made by the authors. However, these studies in the white paper did not provide information on the potential emission reductions from the implementation of an annual, semiannual, quarterly or monthly OGI monitoring and repair program. A report was found after the publication of the white paper from the Colorado Air Quality Control Commission[21] which estimated 40 percent reduction for annual OGI monitoring for well production tank batteries with an uncontrolled VOC emissions of greater than 6 tpy or less than or equal to 12 tpy ($\geq$ 6 to $\leq$ 12 tpy), 60 percent reduction for quarterly OGI monitoring for well production tank batteries with an uncontrolled VOC emissions of greater than 12 tpy and less than or equal to 50 tpy (> 12 to $\leq$ 50 tpy), and 80 percent reduction for monthly OGI monitoring at well production tank batteries with an uncontrolled VOC emission greater than 50 tpy (> 50 tpy).

From the review of the studies in the white paper and the Colorado Economic Impact Analysis, the EPA expects the emission reductions from the implementation of an OGI monitoring and repair program to vary depending on the frequency of monitoring. As noted above, Colorado estimated that monthly monitoring would achieve 80 percent at well production tank batteries with an uncontrolled VOC emission

[20] U.S. EPA Office of Air Quality Planning and Standards, *Oil and Natural Gas Sector Leaks*, located at https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-5110. April 2014.
[21] Colorado Air Quality Control Commission, *Cost-Benefit Analysis for Proposed Revisions to Regulation Number 3 and 7 (5 CCR 1001-5 and 5 CCR 1001-9).* February 7, 2014.

rate of greater than 50 tpy. We believe, based on our review of the studies, monthly monitoring should achieve much higher emission reductions.

Data from the EPA Protocol document estimates monthly Method 21 monitoring to achieve 87 percent reductions at a leak definition of 10,000 ppm and 92 percent reductions at a leak definition of 500 ppm. Potential emissions reductions for annual, semiannual, and quarterly monitoring frequencies[22] were calculated using the data from the EPA Protocol document. For quarterly monitoring, the Method 21 data from the EPA Protocol document estimates a 67 percent reduction at a leak definition of 10,000 ppm and an 83 percent reduction at a leak definition of 500 ppm. Using Method 21 data from the EPA Protocol document, we estimated the percent reductions from semiannual monitoring to be 55 percent at a leak definition of 10,000 ppm and 75 percent reduction at a leak definition of 500 ppm. The potential emission reduction percentages for annual monitoring were calculated to be 42 percent at a leak definition of 10,000 ppm and 68 percent at a leak definition of 500 ppm.

OGI equipment meeting the requirements of 40 CFR 60.5397a(c)(7)(i) are capable of viewing fugitive emissions located at oil and natural gas well sites and compressor stations. The sensitivity (*i.e.*, detection limit) of the currently available OGI equipment varies based on changes in the fugitive compound(s) being imaged, ambient conditions (*i.e.*, sky condition, wind speed, and background temperature), distance of the operator from the fugitive emissions source, and the visual acuity of the operator. Because of the subjectivity of the measurement and variability in typical field ambient conditions, it is not possible to correlate OGI detection capabilities with a Method 21 instrument reading, provided in ppm. However, based on our 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]

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[22] Memorandum to Jodi Howard, U.S. EPA from Bradley Nelson, EC/R, "Estimation of Potential Emission Reductions with the Implementation of a Method 21 Monitoring Program". April 2016. Docket ID No. EPA-HQ-OAR-2010-0505-7625.

[23] Note: EPA previously stated that "the OGI camera is capable of viewing leaks at a 500 ppm level" in the 2016 Final TSD. While EPA agrees that in a controlled laboratory setting under optimal conditions, OGI equipment may be capable of detecting concentrations of this magnitude, it is unlikely that this magnitude of leak would be visible in a field setting. We acknowledge this in the preamble to the 2016 NSPS OOOOa, "At this threshold [500 ppm], the operator would have to repair every component found to have fugitive emissions over 500 ppm threshold. This results in emission reductions greater than the emission reductions that would be achieved if OGI were used instead." 81 FR 35857. For more information on the detection capability of OGI equipment, see https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-4949.

A study performed by ICF[24] using data from Subpart W, EPA/ GRI, City of Fort Worth Natural Gas Air Quality Study, UT Study - Methane Emissions in the Natural Gas Supply Chain: Production, UT Study - Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States Pneumatic Controllers and Jonah Energy LLC WCCA Spring Meeting Presentation determined that the Year 3 fugitive emissions reductions from a quarterly LDAR program to be 78 percent. The data provided in the study supports 40, 60, 80 percent emission reductions for annual, semiannual and quarterly monitoring, respectively.

On the basis of the analysis and the data described here, it was concluded that an OGI monitoring program in combination with a repair program can reduce fugitive methane and VOC emissions from these segments by 40 percent on an annual frequency, 60 percent on a semiannual frequency and 80 percent on a quarterly frequency as well as minimize the loss of salable gas.

In addition to the quarterly, semiannual, and annual monitoring frequencies, we evaluated a stepped down monitoring frequency for well sites that would require semiannual monitoring for the 2-year period following the initial monitoring, followed by annual monitoring from that point forward. One petitioner asserted that the EPA's cost-effectiveness analysis was not accurate and should be revised.[25] In support, the petitioner provided data (which is described in more detail below). The petitioner suggested that, at a minimum, the EPA should require semiannual monitoring at well sites for an initial period of 2 years followed by less frequent monitoring frequencies such as annual monitoring for sites that do not have a significant number of "leaking"[26] components.[27] To evaluate the emission reduction potential of the OGI monitoring and repair program at this stepped frequency, we limited the analysis to the first 8 years of applicability because our cost estimates, described later in this document, consider the impacts for an 8-year period. We applied the 60 percent emission reduction for semiannual monitoring for 2 years and the 40 percent emission reduction for annual monitoring for 6 years, then annualized this percentage to determine the emission reduction of the stepped monitoring frequency of 45 percent.

For low production well sites we also evaluated monitoring once every other year (*i.e.*, biennial monitoring). To evaluate the emission reduction potential of the OGI monitoring and repair program at biennial monitoring, we estimated the percent reduction achieved at a biennial monitoring frequency with

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[24] ICF International, Leak Detection and Repair Cost-Effectiveness Analysis, Prepared for Environmental Defense Fund, December 4, 2015, Revised May 2, 2016. Available at https://www.edf.org/sites/default/files/content/edf_ldar_analysis_120415_v7.pdf.

[25] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.

[26] While the petitioner used the term leaking, the EPA is clarifying they were referring to fugitive emissions, and not equipment leaks such as those subject to a leak detection and repair (LDAR) program at onshore natural gas processing plants.

[27] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.

a 10,000 ppm leak definition using Method 21. This analysis resulted in a 30 percent emission reduction for biennial monitoring.

2.4.1.3 Cost Impacts of OGI-Based Program

Costs for preparing an OGI fugitive emission monitoring and repair plan for a company defined area (*i.e.,* field or district) were estimated using hourly estimates for each of the monitoring and repair plan elements. The costs are based on the following assumptions (costs are presented in 2016$):

- Labor cost for each of the monitoring plan elements, such as reading the rule, was estimated to be $61.21 per hour.
- Reading of the rule and instructions would take 1 person 4 hours to complete at a cost of $245.
- Development of a fugitive emission monitoring plan would take 2.5 people a total of 60 hours to complete at a cost of $3,672.
- Initial activities planning are estimated to take 2 people a total of 8 hours per person for each monitoring event. Cost for biennial monitoring was estimated to be $490, annual monitoring was estimated to be $979, semiannual monitoring was estimated to be $1,959, and stepped monitoring $1,224 for well sites. For compressor stations, the initial activities planning cost are estimated at $1,959 for all monitoring frequencies.
- Notification of compliance status was estimated to take 1 person 1 hour to complete at a cost of $61.21 per well site and compressor stations. We estimated that 22 well sites within each company-defined area for a total of $1,347 for well sites. We estimated 7 gathering and boosting stations per company for a total of $428 and 1 transmission or storage station per notification for a total of $61.21 per transmission and storage station.

Costs for implementing a fugitive emission monitoring plan for a company defined area (*i.e.,* field or district) were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

- Subsequent activities planning are estimated to take 2 people a total of 8 hours per person to complete at a cost of $979 per monitoring event for well sites. For oil and natural gas production well sites, this cost was divided among the total number of well sites owned in a company defined area, which was assumed to be 22. The cost per well site was estimated to be $45 per monitoring event. For compressor stations, the subsequent activities planning are estimated to take 2 people 12 hours per person to complete at a cost of $1,469.

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- The cost for OGI monitoring using an outside contractor was assumed to be $635 for a well site for each monitoring event and $2,300 for each compressor station monitoring event.[28]
- Annual repair costs were estimated to be $316 per monitoring event for well sites, $3,638 per monitoring event for gathering and boosting stations, $3,559 per monitoring event for transmission stations, and $7,355 per monitoring event for storage stations. These costs were estimated assuming that 1.18 percent of the components are identified with fugitive emissions[29] during monitoring and 75 percent are repaired online and 25 percent are repaired offline.
- Costs to resurvey the repaired components that could not be fixed during the initial survey using a Method 21 device was estimated using a resurvey time of 5 minutes per leak at a cost of $61.21 per hour. This assumes the company is able to perform the resurvey without retaining contractors.
- Preparation of annual reports was estimated to take 1 person a total of 4 hours to complete at a cost of $245.

The initial setup cost or capital cost for oil and natural gas well sites was calculated by summing up the costs for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, and notification of initial compliance status. In 2016, we assumed that each company defined area would require the purchase of an instrument to perform Method 21 monitoring for the resurvey. However, it is our understanding that if repairs are not made during the monitoring event, OGI or the alternative method in section 8.3.3 of Method 21 (soap solution) are used instead. Therefore, the cost estimates were updated to remove the capital cost of purchasing a Method 21 instrument.

The total capital cost of these activities was calculated to be $5,753 per company defined area for biennial monitoring, $6,243 for annual monitoring, $6,488 for the stepped monitoring, and $7,222 for semiannual monitoring. Assuming that each company owns and operates 22 well sites within a company defined area[30], the capital cost per well site was estimated to be $262 for biennial monitoring, $284 for annual monitoring, $295 for stepped monitoring, and $328 for semiannual monitoring. For gathering and boosting compressor stations the capital cost for reading the rule, development of fugitive emissions monitoring plan, and initial activities planning notification of initial compliance status was calculated to be

[28] Costs for contractor based OGI monitoring obtained from the Carbon Limits report.

[29] The assumption of 1.18% leak rate for OGI monitoring was obtained from Table 5 of the Uniform Standards memorandum. The 1.18% value is the baseline leak frequency for valves in gas/vapor service. None of the other baseline frequencies in this table were used because the equipment are in liquid service (*e.g.*, pumps LL, valve LL, agitators LL). There is no information on the number of leaks located at uncontrolled facilities, only average percentages of the total number of components at a facility. Therefore, our methodology was to use the 1.18% leak frequency value from the Uniform Standards memorandum and apply that value to the total number of components at the oil and natural gas model plant. (Uniform Standards Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180).

[30] The number of well sites owned and operated by companies was calculated using data from the Fort Worth study.

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$6,304, which was assumed to be shared between 7 gathering and boosting stations within the company defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210 mile radius of a central location, the capital cost of each of these stations was estimated to be $901. For transmission and storage stations, the capital cost per facility was calculated to be $5,937.

For all oil and natural gas segments, the annual cost includes subsequent activities planning, OGI survey, cost of repair of fugitive emissions found, resurvey of repaired components, preparation and submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. For our analysis the EPA calculated the annual cost for annual, stepped, and semiannual OGI surveys at well sites, and annual, semiannual, and quarterly OGI surveys at compressor stations. The annual cost for the biennial monitoring frequency was estimated by assuming the annual monitoring frequency values were incurred during the years when monitoring takes place and no annual cost in the years when monitoring does not occur. The OGI monitoring cost memorandum[31] presented in 2016 contains the analyses for other costing methodologies, including a company-based OGI monitoring program and an OGI program using cost methodologies developed for the Colorado fugitive leak program to estimate the annual cost of implementing an OGI monitoring and repair program for oil and natural gas well sites, gathering and boosting, transmission and storage compressor stations for the respective OGI monitoring frequencies. This memorandum was not updated for this reconsideration.

The cost per ton of emissions reduced was calculated using two separate methods. The first method allocated all of the costs to one pollutant and zero to the other (single-pollutant approach) using representative unit costs for each control option. The second method allocated the annual cost among the pollutants (*i.e.,* GHG (in the form of limiting methane emissions) and VOC) that a given technology reduced (multi-pollutant approach). This proration was based on estimates of the percentage reduction expected for each pollutant. In the case of fugitives, the percent reductions for methane and VOC emissions are equal; and therefore, the proration of the annual cost was divided equally and applied to the methane and VOC reductions.

Based on estimated emissions reductions and the estimated cost for implementing an OGI fugitive emissions monitoring and repair program at the affected facilities, the EPA calculated a cost of control for methane and VOC for the various options for oil and natural gas production well sites, gathering and boosting, and transmission and storage compressor stations. The EPA then calculated the cost of control of

[31] Memorandum to Jodi Howard, U.S. EPA from Bradley Nelson, EC/R. "Evaluation of Cost methodologies for OGI Monitoring". April 2016. Docket ID No. EPA-HQ-OAR-2010-0505-7624.

well sites and compressor stations using the weighted average cost of control for all well sites and all compressor stations (*i.e.,* gathering and boosting, transmission and storage). Tables 2-9, 2-10, 2-11, 2-12, and 2-13 present a summary of the cost of control for methane and VOC for the various OGI monitoring frequency options (*i.e.,* biennial, annual, semiannual, stepped, and quarterly, respectively).

2.4.1.4 Secondary Impacts

No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of fugitive emissions components. There are some emissions that would be generated by the OGI camera monitoring contractors with respect to driving to and from the site for the fugitive emissions survey. Using AP-42 mobile emission factors[32] and assuming a distance of 70 miles to the well site or compressor station, the emissions generated from semiannual monitoring at a well site (140 miles to and from the well site twice a year) is estimated to be 0.35 pounds per year (lb/yr) of hydrocarbons, 6.0 lb/yr of carbon monoxide (CO) and 0.40 lb/yr of nitrogen dioxides (NO_X). The emissions generated from quarterly monitoring at a compressor station (140 miles to and from the compressor station four times a year) is estimated to be 0.70 lb/yr of hydrocarbons, 12.0 lb/yr of CO and 0.80 lb/yr of NO_X.

Table 2-9. Summary of the Model Plant Cost of Control for Biennial OGI Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	Methane	VOC	Methane	VOC
Single Pollutant Approach				
Low Production Well Site Program	$1,104	$3,972	$906	$3,259
Multipollutant Approach				
Low Production Well Site Program	$552	$1,986	$453	$1,629

a. The weighted average for the segments were calculated using the 2014 activity counts of 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), and 1,222 low production oil well sites (GOR>300).
b. Recovery credits for oil and natural gas production well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42 Mcf.

[32] AP-42: Compilation of Air Pollutant Emission Factors. Highway Vehicles, Light-Duty Gasoline Truck I, Model Year 1998+, 50,000 miles. https://www3.epa.gov/otaq/ap42.htm#highway.

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Table 2-10. Summary of the Model Plant Cost of Control for Annual OGI Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	Methane	VOC	Methane	VOC
Single Pollutant Approach				
Non-Low Production Well Site Program	$979	$3,523	$781	$2,810
Low Production Well Site Program	$1,360	$4,893	$1,140	$4,102
Compressor Station Program	$557	$2,414	$396	$1,717
Multipollutant Approach				
Non-Low Production Well Site Program	$490	$1,761	$391	$1,405
Low Production Well Site Program	$680	$2,446	$570	$2,051
Compressor Station Program	$278	$1,207	$198	$859

a. The weighted average for the segments were calculated using the 2014 activity counts of 2,001 non-low production gas well sites, 1,848 non-low production oil well sites (GOR<300), 9,190 non-low production oil well sites (GOR>300), 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), 1,222 low production oil well sites (GOR>300), 212 G&B stations, 36 transmission stations, and 2 storage facilities.
b. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42 Mcf.
Note: Transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

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Table 2-11. Summary of the Model Plant Cost of Control for Semiannual OGI Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	Methane	VOC	Methane	VOC
Single Pollutant Approach				
Non-Low Production Well Site Program	$1,164	$4,186	$965	$3,473
Low Production Well Site Program	$1,616	$5,814	$1,396	$5,023
Compressor Station Program	$652	$2,827	$491	$2,130
Multipollutant Approach				
Non-Low Production Well Site Program	$582	$2,093	$483	$1,736
Low Production Well Site Program	$808	$2,907	$698	$2,512
Compressor Station Program	$326	$1,413	$246	$1,065

a. The weighted average for the segments were calculated using the 2014 activity counts of 2,001 non-low production gas well sites, 1,848 non-low production oil well sites (GOR<300), 9,190 non-low production oil well sites (GOR>300), 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), 1,222 low production oil well sites (GOR>300), 212 G&B stations, 36 transmission stations, and 2 storage facilities.
b. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42 Mcf.
Note: Transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

Table 2-12. Summary of the Model Plant Cost of Control for Stepped OGI Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	Methane	VOC	Methane	VOC
Single Pollutant Approach				
Non-Low Production Well Site Program	$1,041	$3,744	$842	$3,031
Low Production Well Site Program	$1,445	$5,200	$1,247	$4,487
Multipollutant Approach				
Non-Low Production Well Site Program	$520	$1,872	$421	$1,515
Low Production Well Site Program	$723	$2,600	$624	$2,243

a. The weighted average for the segments were calculated using the 2014 activity counts of 2,001 non-low production gas well sites, 1,848 non-low production oil well sites (GOR<300), 9,190 non-low production oil well sites (GOR>300), 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), and 1,222 low production oil well sites (GOR>300).
b. Recovery credits for oil and natural gas production well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42 Mcf.

Table 2-13. Summary of the Model Plant Cost of Control for Quarterly OGI Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	Methane	VOC	Methane	VOC
Single Pollutant Approach				
Compressor Station Program	$910	$3,946	$749	$3,250
Multipollutant Approach				
Compressor Station Program	$455	$1,973	$375	$1,625

a. The weighted average for the segments were calculated using the 2014 activity counts of 21 G&B stations, 36 transmission stations, and 2 storage facilities.
b. Recovery credits for gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42 Mcf.

2.4.2 Fugitive Emissions Detection and Repair with Method 21

In the 2016 NSPS OOOOa, we allowed owners and operators the option to perform fugitive emissions monitoring using Method 21 instead of OGI. Under this option, the reduction of fugitive emissions from well sites and compressor stations also involves the development of a fugitive emissions monitoring plan, except that the monitoring is conducted using Method 21 instead of OGI, as described in section 2.4.1. The Method 21 monitoring includes the development of a fugitive emissions monitoring plant, survey using Method 21 instrumentation, resurvey of components to verify successful repair, and the preparation and submittal of an annual report. The monitoring plan must include an inventory of fugitive emissions components, including information on the component type, type of service (*e.g.*, gas/vapor, light liquid, or heavy liquid), location of the component, and information about each monitoring event specific to the individual component. Additionally, provisions for the repair and resurvey must be included in the monitoring plan. For our analysis, we evaluated two repair thresholds, or instrument readings that would trigger the repair requirements: 500 ppm and 10,000 ppm. Options to reduce emissions under the Method 21 detection option will vary based on the frequency of monitoring and the instrument reading that triggers repair.

2.4.2.1 Method 21 Emission Reduction Potential

The EPA based the emission reduction analysis on the method for estimating leak detection and repair (LDAR) control effectiveness from Chapter 5.3.1 of the Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017). Under this method, the control effectiveness is calculated using a stepwise approach that starts from the initial leak frequency and adds monitoring cycles until the leak

frequency after monitoring reaches steady state. The difference between the initial leak rate and the final leak rate provides the control effectiveness for the fugitive emissions monitoring program. Other parameters included in the monitoring cycle calculations are the percentage of successfully repair components, the percentage of new leaks and the percentage of leaks that were repaired but have reoccurred. The EPA Protocol does not provide these data for oil and natural gas production; only for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) and refineries. The refinery emissions data are provided in non-methane organic compound (NMOC) units, which would require assumed TOC and methane weight fractions to determine the TOC emission factors, whereas the SOCMI emissions data is already based on TOC. The assumed TOC and methane weight fractions would add another level of uncertainty to the emission reduction percentage calculations if the refinery data were used. Therefore, we determined that using the SOCMI data would provide the best estimate of potential fugitive emission reduction percentages for a typical Method 21 monitoring program, and would be comparable to the potential fugitive emission reductions for oil and gas production, if the other parameters were available for this segment. The potential emission reduction from the implementation of a Method 21 program was calculated using this SOCMI data. Table 2-14 provides a summary of the parameters used to calculate the monitoring cycles. An example of the methodology is provided in Chapter 5.3.2 of the EPA Protocol document. The SOCMI data in the EPA Protocol document only included occurrence rates for monthly and quarterly monitoring. To calculate annual and semiannual occurrence rates, a logarithmic equation was derived from the data points. Initial leak frequencies were calculated using the EPA Protocol average leak rate equations for 500 and 10,000 ppm gas valves (see Table 5-4 of the EPA Protocol) and the average SOCMI emission factor for gas valves of 0.00597 kilograms per hour per source (see Table 2-1 of the EPA Protocol) and solving for leak fraction. The initial leak frequencies can also extrapolated using the lines in Figure 5-1 in the EPA Protocol document. The average leak fraction equation and calculated initial leak frequency are provided in Table 2-14.

Using the parameters in Table 2-14, the estimated emission reductions were calculated using the monitoring cycle approach in the EPA Protocol document. The leak frequency after monitoring reached steady state on the sixth monitoring cycle and the percent reduction was calculated. The results of the emission reductions are presented in Table 2-15.[33]

[33] See memorandum *Estimation of Potential Reductions with the Implementation of a Method 21 Monitoring Program*, located at Docket ID No. EPA-HQ-OAR-2010-0505-7625.

Table 2-14. Parameters and Assumptions Used to Calculate Monitoring Cycles

Parameter	Parameter Value (500 ppm)	Parameter Value (10,000 ppm)
Occurrence Rate	5.46% Annual 4.21% Semiannual 2.97% Quarterly	5.46% Annual 4.21% Semiannual 2.97% Quarterly
Recurrence Rate	14%	14%
Unsuccessful Repair Rate	10%	10%
Initial Leak Frequency	13.53%	7.49%
Average Leak Rate Equation	ALR = 0.044*LF + 0.000017	ALR = 0.078*LF + 0.00013

Table 2-15. Percent Reduction in Emissions for EPA Method 21 Monitoring and Repair

Monitoring Frequency	Fugitive Percent Reduction		
	Method 21 Repair Threshold		OGI
	10,000 ppm	500 ppm	
Biennial	30	61	30
Annual	42	68	40
Stepped	45	70	45
Semiannual	55	75	60
Quarterly	67	83	80

As noted in Table 2-15 above, in all cases the percent reduction for the 500 parts per million Method 21 alternative is equal to or greater than the estimated OGI monitoring and repair percent reduction. The percent reduction for the 10,000 parts per million leak threshold was only greater than the OGI option for annual monitoring. Based on the estimated OGI monitoring model plant emission reductions (see Tables 2-9 through 2-13), Table 2-15 summarizes the estimated model plant emission reductions for the alternative Method 21 monitoring and repair option for 500 and 10,000 ppm leak thresholds.

Table 2-16a. Model Plant Emission Reductions for OGI and EPA Method 21

Monitoring and Repair – Well Sites

Affected Facility	OGI Monitoring (tpy)		Method 21 10,000 ppm (tpy)[a]		Method 21 500 ppm (tpy)[a]	
	Methane	VOC	Methane	VOC	Methane	VOC
Annual Monitoring						
Gas Well Sites	2.36	0.66	2.49	0.69	4.04	1.12
Oil Well Sites (GOR < 300)	0.82	0.23	0.87	0.24	1.40	0.39
Oil Well Sites (GOR > 300)	1.22	0.34	1.28	0.36	2.08	0.58
Low Production Gas Well Sites	1.92	0.53	2.03	0.56	3.28	0.91
Low Production Oil Well Sites (GOR < 300)	0.73	0.20	0.77	0.21	1.25	0.35
Low Production Oil Well Sites (GOR > 300)	1.05	0.29	1.11	0.31	1.8	0.50
Stepped Monitoring						
Gas Well Sites	2.66	0.74	2.68	0.75	4.14	1.15
Oil Well Sites (GOR < 300)	0.93	0.26	0.93	0.26	1.44	0.40
Oil Well Sites (GOR > 300)	1.37	0.38	1.38	0.38	2.13	0.59
Low Production Gas Well Sites	2.16	0.60	2.18	0.61	3.37	0.94
Low Production Oil Well Sites (GOR < 300)	0.82	0.23	0.83	0.23	1.28	0.36
Low Production Oil Well Sites (GOR > 300)	1.18	0.33	1.19	0.33	1.84	0.51
Semiannual Monitoring						
Gas Well Sites	3.55	0.99	3.24	0.90	4.46	1.24
Oil Well Sites (GOR < 300)	1.23	0.34	1.13	0.31	1.55	0.43
Oil Well Sites (GOR > 300)	1.82	0.51	1.67	0.46	2.29	0.64
Low Production Gas Well Sites	2.88	0.80	2.63	0.73	3.62	1.01
Low Production Oil Well Sites (GOR < 300)	1.10	0.31	1.00	0.28	1.38	0.38
Low Production Oil Well Sites (GOR > 300)	1.58	0.44	1.44	0.40	1.98	0.55

a. Assumes baseline emissions shown in Tables 2-5 and 2-8 and percent reduction shown in Table 2-21.

Table 2-16b. Model Plant Emission Reductions for OGI and EPA Method 21 Monitoring and Repair – Biennial Monitoring

Affected Facility	OGI Monitoring (tpy)		Method 21 10,000 ppm (tpy)[a]		Method 21 500 ppm (tpy)[a]	
	Methane	VOC	Methane	VOC	Methane	VOC
Biennial Monitoring						
Low Production Gas Well Sites	1.44	0.40	1.44	0.40	2.93	0.81
Low Production Oil Well Sites (GOR < 300)	0.55	0.15	0.55	0.15	1.12	0.31
Low Production Oil Well Sites (GOR > 300)	0.79	0.22	0.79	0.22	1.60	0.45

Table 2-16c. Model Plant Emission Reductions for OGI and EPA Method 21 Monitoring and Repair – Compressor Station

Affected Facility	OGI Monitoring (tpy)		Method 21 10,000 ppm (tpy)[a]		Method 21 500 ppm (tpy)[a]	
	Methane	VOC	Methane	VOC	Methane	VOC
Annual Monitoring						
Gathering & Boosting	14.1	3.91	14.8	4.12	24.0	6.67
Transmission	16.2	0.45	17.0	0.47	27.6	0.76
Storage	57.0	1.58	60.1	1.66	97.3	2.69
Semiannual Monitoring						
Gathering & Boosting	21.1	5.86	19.3	5.35	26.5	7.37
Transmission	24.2	0.67	22.1	0.61	30.5	0.84
Storage	85.5	2.37	78.1	2.16	107.4	2.97
Quarterly Monitoring						
Gathering & Boosting	28.1	7.81	23.7	6.58	29.0	8.06
Transmission	32.3	0.89	27.2	0.75	33.0	0.92
Storage	114.0	3.15	96.0	2.66	117.5	3.25

a. Assumes baseline emissions shown in Tables 2-5 and 2-8 and percent reduction shown in Table 2-21.

2.4.2.3 Cost Impacts of Method 21-Based Program

Costs for preparing a Method 21 fugitive emission monitoring and repair plan for a company defined area (*i.e.,* field or district) were estimated using hourly estimates for each of the monitoring and repair plan elements. The costs are based on the following assumptions (costs are presented in 2016$):

- Labor cost for each of the monitoring plan elements, such as reading the rule, was estimated to be $61.21 per hour.
- Reading of the rule and instructions would take 1 person 4 hours to complete at a cost of $245.
- Development of a fugitive emission monitoring plan would take 2.5 people a total of 60 hours to complete at a cost of $3,672.
- Initial activities planning are estimated to take 2 people a total of 8 hours per person for each monitoring event. Annual cost for biennial monitoring was estimated to be $490, annual monitoring was estimated to be $979, semiannual monitoring was estimated to be $1,959, and stepped monitoring $1,224 for well sites. For compressor stations, the initial activities planning cost are estimated at $1,959 for all monitoring frequencies.
- Notification of compliance status was estimated to take 1 person 1 hour to complete at a cost of $61.21 per well site and compressor stations. We estimated that 22 well sites within each company-defined area for a total of $1,347 for well sites. We estimated 7 gathering and boosting stations per company for a total of $428 and 1 transmission or storage station per notification for a total of $61.21 per transmission and storage station.
- It was estimated that a Method 21 monitoring instrument costs $10,800 instrument and the data collection system costs $14,500.

Costs for implementing a fugitive emission monitoring plan for a company defined area (*i.e.,* field or district) were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

- Subsequent activities planning are estimated to take 2 people a total of 8 hours per person to complete at a cost of $979 per monitoring event at well sites. For oil and natural gas production well sites, this cost was divided among the total number of well sites owned in a company defined area, which was assumed to be 22. The cost per well site was estimated to be $45 per monitoring event. The subsequent activities planning are estimated to take 2 people a total of 12 hours per person to complete at a cost of $1,469 per monitoring event for compressor stations.

- The Method 21 monitoring survey was estimated to take 2 people a total of 8 hours per person to complete at a cost of $979 for each monitoring event at a well site. For gathering and boosting stations, it was estimated to take 2 people a total of 16 hours per person to complete a Method 21 survey at a cost of $1,959 for each monitoring event. For transmission stations, it was estimated to take 2 people a total of 23 hours per person to complete a Method 21 survey at a cost of $2,815 per monitoring event. For storage stations, it was estimated to take 2 people a total of 42 hours to complete a Method 21 survey at a cost of $5,141.[34]
- Annual repair costs were estimated to be $316 per monitoring event for well sites, $3,638 per monitoring event for gathering and boosting stations, $3,559 per monitoring event for transmission stations, and $7,355 per monitoring event for storage stations. These costs were estimated assuming that 1.18 percent of the components are identified with fugitive emissions[35] during monitoring and 75 percent are repaired online and 25 percent are repaired offline.
- Costs to resurvey the repaired components that could not be fixed during the initial survey using a Method 21 device was estimated using a resurvey time of 5 minutes per leak at a cost of $61.21 per hour. This assumes the company is able to perform the resurvey without retaining contractors.
- Preparation of annual reports was estimated to take 1 person a total of 4 hours to complete at a cost of $245.

The initial setup cost or capital cost for oil and natural gas well sites was calculated by summing up the costs for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, and notification of initial compliance status. The total capital cost of these activities at well sites was calculated to be $31,053 per company defined area for biennial monitoring, $31,543 for annual monitoring, $31,788 for the stepped monitoring, and $32,522 for semiannual monitoring. Assuming that each company owns and operates 22 well sites within a company defined area[36], the capital cost per well site was estimated to be $1,412 for biennial monitoring, $1,434 for annual monitoring, $1,445 for stepped monitoring and $1,478 for semiannual monitoring. For gathering and boosting compressor stations the capital cost for reading the rule, development of fugitive emissions monitoring plan, and initial activities

[34] Costs for contractor based OGI monitoring obtained from the Carbon Limits report.

[35] The assumption of 1.18% leak rate for OGI monitoring was obtained from Table 5 of the Uniform Standards memorandum. The 1.18% value is the baseline leak frequency for valves in gas/vapor service. None of the other baseline frequencies in this table were used because the equipment are in liquid service (*e.g.*, pumps LL, valve LL, agitators LL). There is no information on the number of leaks located at uncontrolled facilities, only average percentages of the total number of components at a facility. Therefore, our methodology was to use the 1.18% leak frequency value from the Uniform Standards memorandum and apply that value to the total number of components at the oil and natural gas model plant. (Uniform Standards Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180).

[36] The number of well sites owned and operated by companies was calculated using data from the Fort Worth study.

planning notification of initial compliance status was calculated to be $31,237, which was assumed to be shared between 7 gathering and boosting stations within the company defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210 mile radius of a central location, the capital cost of each of these stations was estimated to be $4,462. For transmission and storage stations, the capital cost per facility was calculated to be $31,237.

For all oil and natural gas segments, the annual cost includes subsequent activities planning, Method 21 survey, cost of repair of fugitive emissions found, resurvey of repaired components, preparation and submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. For our analysis the EPA calculated the annual cost for annual, stepped, and semiannual Method 21 surveys at well sites, and annual, semiannual, and quarterly Method 21 surveys at compressor stations.

We use the same two methods (single pollutant and multipollutant) discussed in section 2.4.1.3 for the Method 21 program. Based on estimated emissions reductions and the estimated cost for implementing a Method 21 fugitive emissions monitoring and repair program at the affected facilities, the EPA calculated a cost of control for methane and VOC for the various options for oil and natural gas production well sites, gathering and boosting, and transmission and storage compressor stations. The EPA then calculated the cost of control of well sites and compressor stations using the weighted average cost of control for all well sites and all compressor stations (*i.e.*, gathering and boosting, transmission and storage). Tables 2-17, 2-18, 2-19, 2-20, and 2-21 present a summary of the cost of control for methane and VOC for the various Method 21 monitoring frequency options (*i.e.*, biennial, annual, semiannual, stepped, and quarterly, respectively).

2.4.2.4 Secondary Impacts

No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of fugitive emissions components. There are some emissions that would be generated by the Method 21 monitoring contractors with respect to driving to and from the site for the fugitive emissions survey, as discussed in section 2.4.1.4 for OGI. We assume the same mobile emissions from the Method 21 program.

Table 2-17. Summary of the Model Plant Cost of Control for Biennial Method 21 Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	500 ppm				10,000 ppm			
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Single Pollutant Approach								
Low Production Well Site Program	$791	$2,847	$593	$2,134	$1,609	$5,789	$1,411	$5,076
Multipollutant Approach								
Low Production Well Site Program	$396	$1,423	$297	$1,067	$805	$2,894	$705	$2,538

a. The weighted average for the segments were calculated using the 2014 activity counts of 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), and 1,222 low production oil well sites (GOR>300).
b. Recovery credits for oil and natural gas production well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42/ Mcf.

Table 2-18. Summary of the Model Plant Cost of Control for Annual Method 21 Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	500 ppm				10,000 ppm			
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Single Pollutant Approach								
Non-Low Production Well Site Program	$809	$2,909	$610	$2,196	$1,309	$4,708	$1,110	$3,995
Low Production Well Site Program	$1,123	$4,040	$925	$3,327	$1,818	$6,539	$1,619	$5,826
Compressor Station Program	$376	$1,632	$216	$935	$609	$2,642	$448	$1,945
Multipollutant Approach								
Non-Low Production Well Site Program	$404	$1,454	$305	$1,098	$654	$2,354	$555	$1,997
Low Production Well Site Program	$562	$2,020	$462	$1,664	$909	$3,269	$810	$2,913
Compressor Station Program	$188	$816	$108	$468	$305	$1,321	$224	$972

a. The weighted average for the segments were calculated using the 2014 activity counts of 2,001 non-low production gas well sites, 1,848 non-low production oil well sites (GOR<300), 9,190 non-low production oil well sites (GOR>300), 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), 1,222 low production oil well sites (GOR>300), 212 G&B stations, 36 transmission stations, and 2 storage facilities.

b. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42/ Mcf.

Note: Transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

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Table 2-19. Summary of the Model Plant Cost of Control for Semiannual Method 21 Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	500 ppm				10,000 ppm			
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Single Pollutant Approach								
Non-Low Production Well Site Program	$1,275	$4,588	$1,077	$3,875	$1,755	$6,313	$1,557	$5,600
Low Production Well Site Program	$1,771	$6,372	$1,573	$5,659	$2,437	$8,768	$2,239	$8,055
Compressor Station Program	$568	$2,465	$408	$1,768	$782	$3,392	$621	$2,695
Multipollutant Approach								
Non-Low Production Well Site Program	$638	$2,294	$539	$1,937	$877	$3,156	$778	$2,800
Low Production Well Site Program	$886	$3,186	$787	$2,830	$1,219	$4,384	$1,120	$4,027
Compressor Station Program	$284	$1,233	$204	$884	$391	$1,696	$311	$1,348

a. The weighted average for the segments were calculated using the 2014 activity counts of 2,001 non-low production gas well sites, 1,848 non-low production oil well sites (GOR<300), 9,190 non-low production oil well sites (GOR>300), 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), 1,222 low production oil well sites (GOR>300), 212 G&B stations, 36 transmission stations, and 2 storage facilities.

b. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42/ Mcf.

Note: Transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

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Table 2-20. Summary of the Model Plant Cost of Control for Stepped Method 21 Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	500 ppm				10,000 ppm			
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Single Pollutant Approach								
Non-Low Production Well Site Program	$965	$3,471	$767	$2,758	$1,491	$5,363	$1,293	$4,650
Low Production Well Site Program	$1,340	$4,820	$1,142	$4,107	$2,071	$7,449	$1,872	$6,736
Multipollutant Approach								
Non-Low Production Well Site Program	$482	$1,735	$383	$1,379	$745	$2,681	$646	$2,325
Low Production Well Site Program	$670	$2,410	$571	$2,054	$1,035	$3,724	$936	$3,368

a. The weighted average for the segments were calculated using the 2014 activity counts of 2,001 non-low production gas well sites, 1,848 non-low production oil well sites (GOR<300), 9,190 non-low production oil well sites (GOR>300), 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), and 1,222 low production oil well sites (GOR>300).
b. Recovery credits for oil and natural gas production well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42/ Mcf.

Table 2-21. Summary of the Model Plant Cost of Control for Quarterly Method 21 Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	500 ppm				10,000 ppm			
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Single Pollutant Approach								
Compressor Station Program	$935	$4,057	$775	$3,360	$1,145	$4,965	$984	$4,269
Multipollutant Approach								
Compressor Station Program	$468	$2,028	$387	$1,680	$573	$2,483	$492	$2,134

a. The weighted average for the segments were calculated using the 2014 activity counts of 212 G&B stations, 36 transmission stations, and 2 storage facilities.
b. Recovery credits were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition for gathering and boosting and the value of the natural gas recovered as $3.42/ Mcf.

2.5 Regulatory Options

As discussed in section 2.4, we continue to conclude that a fugitive emissions monitoring and repair program using OGI or Method 21 is the most viable method for reducing fugitive emissions at well sites and compressor stations. Therefore, we evaluated the following regulatory options to evaluate both monitoring techniques:

- Regulatory Option 1: The implementation of a fugitive emissions monitoring and repair program using OGI as the detection method. The following sub-options were evaluated for different monitoring frequencies, as shown below.
    - 1a. Monitoring on an annual frequency at well sites and compressor stations.
    - 1b. Monitoring on a semiannual frequency for 2 years, followed by annual monitoring thereafter at well sites.
    - 1c. Monitoring on a semiannual frequency at well sites and compressor stations.
    - 1d. Monitoring on a quarterly frequency at compressor stations.
    - 1e. Monitoring on a biennial frequency at low production well sites.
- Regulatory Option 2: The implementation of a fugitive emissions monitoring and repair program using Method 21 as the detection method, with a repair threshold of 500 ppm. The following sub-options were evaluated for different monitoring frequencies, as shown below.
    - 2a. Monitoring on an annual frequency at well sites and compressor stations.
    - 2b. Monitoring on a semiannual frequency for 2 years, followed by annual monitoring thereafter at well sites.
    - 2c. Monitoring on a semiannual frequency at well sites and compressor stations.
    - 2d. Monitoring on a quarterly frequency at compressor stations.
    - 2e. Monitoring on a biennial frequency at low production well sites.
- Regulatory Option 3: The implementation of a fugitive emissions monitoring and repair program using Method 21 as the detection method, with a repair threshold of 10,000 ppm. The following sub-options were evaluated for different monitoring frequencies, as shown below.
    - 3a. Monitoring on an annual frequency at well sites and compressor stations.
    - 3b. Monitoring on a semiannual frequency for 2 years, followed by annual monitoring thereafter at well sites.
    - 3c. Monitoring on a semiannual frequency at well sites and compressor stations.
    - 3d. Monitoring on a quarterly frequency at compressor stations.
    - 3e. Monitoring on a biennial frequency at low production well sites.

2.5.1 Evaluation of Regulatory Options for Fugitive Emissions

As noted above, the EPA calculated a weighted average cost of control for non-low production and low production well sites (which includes oil wells, oil wells with associated gas, and natural gas production well sites) and compressor stations (which includes gathering and boosting stations, transmission stations and storage facilities). For ease of review the EPA has summarized the cost of control for the options for well sites and compressor stations in Table 2-22.

2.5.1.1 Option 1 – OGI Monitoring

Non-Low Production Well Sites. For non-low production well sites, we have three sub-options based on the frequency of OGI monitoring conducted, Options 1a, 1b, and 1c. Under the single pollutant approach for the annual monitoring frequency (Option 1a), if all costs are assigned to methane and zero to VOC reductions, the cost is $972 per ton of methane reduced, and $773 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,495 per ton of VOC reduced, and $2,782 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $1,748 per ton VOC reduced, and $1,391 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $486 per ton methane reduced, and $387 per ton if natural gas savings are considered.

Under the single pollutant approach for the stepped monitoring frequency (Option 1b), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,032 per ton of methane reduced, and $834 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,713 per ton of VOC reduced, and $3,000 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual to annual monitoring is $1,857 per ton VOC reduced, and $1,500 per ton if natural gas savings are considered. The control cost for methane based on semiannual to annual monitoring under the multipollutant approach is $516 per ton methane reduced, and $417 per ton if natural gas savings are considered.

Finally, for semiannual monitoring (Option 1c) of non-low production well sites, under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,153 per ton of methane reduced, and $955 per ton if savings of the natural gas recovered is considered. Likewise,

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if all costs are assigned to VOC reduction, the cost is $4,149 per ton of VOC reduced, and $3,436 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $2,075 per ton VOC reduced, and $1,718 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $577 per ton methane reduced, and $478 per ton if natural gas savings are considered.

Low Production Well Sites. Similarly for low production well sites, under the single pollutant approach for the annual monitoring frequency (Option 1a), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,360 per ton of methane reduced, and $1,140 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,893 per ton of VOC reduced, and $4,102 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $2,446 per ton VOC reduced, and $2,051 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $680 per ton methane reduced, and $570 per ton if natural gas savings are considered.

Under the single pollutant approach for the stepped monitoring frequency (Option 1b), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,445 per ton of methane reduced, and $1,247 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $5,200 per ton of VOC reduced, and $4,487 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on stepped monitoring is $2,600 per ton VOC reduced, and $2,243 per ton if natural gas savings are considered. The control cost for methane based on semiannual to annual monitoring under the multipollutant approach is $723 per ton methane reduced, and $624 per ton if natural gas savings are considered.

For semiannual monitoring (Option 1c), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,616 per ton of methane reduced, and $1,396 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $5,814 per ton of VOC reduced, and $5,023 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $2,907 per ton VOC reduced, and $2,512 per ton if natural gas savings

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are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $808 per ton methane reduced, and $698 per ton if natural gas savings are considered.

Finally for the biennial monitoring (Option 1e), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,104 per ton of methane reduced, and $906 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,972 per ton of VOC reduced, and $3,259 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on biennial monitoring is $1,986 per ton VOC reduced, and $1,629 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $552 per ton methane reduced, and $453 per ton if natural gas savings are considered.

Wellhead Only Well Sites. For wellhead only well sites, under the single pollutant approach for the annual monitoring frequency (Option 1a), if all costs are assigned to methane and zero to VOC reductions, the cost is $6,349 per ton of methane reduced, and $5,064 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $22,840 per ton of VOC reduced, and $18,217 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $11,420 per ton VOC reduced, and $9,109 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $3,174 per ton methane reduced, and $2,532 per ton if natural gas savings are considered. Given these high cost for control, we did not evaluate more frequent monitoring at these wellhead only well sites.

Compressor Stations. For compressor stations, under the single pollutant approach for the annual monitoring frequency (Option 1a), if all costs are assigned to methane and zero to VOC reductions, the cost is $557 per ton of methane reduced, and $396 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $2,414 per ton of VOC reduced, and $1,717 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $1,207 per ton VOC reduced, and $859 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $278 per ton methane reduced, and $198 per ton if natural gas savings are considered.

Under the single pollutant approach for semiannual monitoring (Option 1c), if all costs are assigned to methane and zero to VOC reductions, the cost is $652 per ton of methane reduced, and $491

per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $2,827 per ton of VOC reduced, and $2,130 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $1,413 per ton VOC reduced, and $1,065 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $326 per ton methane reduced, and $246 per ton if natural gas savings are considered.

Finally, for quarterly monitoring (Option 1d), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $910 per ton of methane reduced, and $749 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,946 per ton of VOC reduced, and $3,250 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on quarterly monitoring is $1,973 per ton VOC reduced, and $1,625 per ton if natural gas savings are considered. The control cost for methane based on quarterly monitoring under the multipollutant approach is $455 per ton methane reduced, and $375 per ton if natural gas savings are considered.

Because the gas handled by transmission and storage facilities is not typically owned by these facilities, we do not consider the value of the gas saved as an offset to the cost. However, for gathering and boosting stations, the gas savings could be considered. Therefore, we calculated the cost of control for compressor stations considering the gas savings contributed by gathering and boosting stations. This cost savings is reflected in the cost presented above and summarized in Table 2-22.

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Table 2-22. Summary of the Cost of Control for the OGI Monitoring Options

Option	Cost of Control (without gas savings)				Cost of Control (with gas savings)			
	Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)		Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Non-Low Production Well Sites								
1a - Annual	$979	$3,523	$490	$1,761	$781	$2,810	$391	$1,405
1b - Stepped	$1,041	$3,744	$520	$1,872	$842	$3,031	$421	$1,515
1c - Semiannual	$1,164	$4,186	$582	$2,093	$965	$3,473	$483	$1,736
Low Production Well Sites								
1a - Annual	$1,360	$4,893	$680	$2,446	$1,140	$4,102	$570	$2,051
1b - Stepped	$1,445	$5,200	$723	$2,600	$1,247	$4,487	$624	$2,243
1c - Semiannual	$1,616	$5,814	$808	$2,907	$1,396	$5,023	$698	$2,512
1e – Biennial	$1,104	$3,972	$552	$1,986	$906	$3,259	$453	$1,629
Wellhead Only Well Sites								
1a - Annual	$6,349	$22,840	$3,174	$11,420	$5,064	$18,217	$2,532	$9,109
Compressor Stations								
1a - Annual	$557	$2,414	$278	$1,207	$396	$1,717	$198	$859
1b - Semiannual	$652	$2,827	$326	$1,413	$491	$2,130	$246	$1,065
1d - Quarterly	$910	$3,946	$455	$1,973	$749	$3,250	$375	$1,625

2.5.1.2 Option 2 – Method 21 Monitoring with a 500 ppm Repair Threshold

Non-Low Production Well Sites. The same three sub-options used in section 2.5.1.1 were evaluated for Method 21 monitoring with a 500 ppm repair threshold, Options 2a, 2b, and 2c. Under the single pollutant approach for the annual monitoring frequency (Option 2a), if all costs are assigned to methane and zero to VOC reductions, the cost is $809 per ton of methane reduced, and $610 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $2,909 per ton of VOC reduced, and $2,196 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $1,454 per ton VOC reduced, and $1,098 per ton if natural gas savings are considered. The

control cost for methane based on annual monitoring under the multipollutant approach is $404 per ton methane reduced, and $305 per ton if natural gas savings are considered.

Under the single pollutant approach for the stepped monitoring frequency (Option 2b), if all costs are assigned to methane and zero to VOC reductions, the cost is $965 per ton of methane reduced, and $767 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,471 per ton of VOC reduced, and $2,758 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual to annual monitoring is $1,735 per ton VOC reduced, and $1,379 per ton if natural gas savings are considered. The control cost for methane based on semiannual to annual monitoring under the multipollutant approach is $482 per ton methane reduced, and $383 per ton if natural gas savings are considered.

Finally, for semiannual monitoring (Option 2c) of non-low production well sites, under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,275 per ton of methane reduced, and $1,077 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,588 per ton of VOC reduced, and $3,875 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $2,294 per ton VOC reduced, and $1,937 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $638 per ton methane reduced, and $539 per ton if natural gas savings are considered.

Low Production Well Sites. Similarly for low production well sites, under the single pollutant approach for the annual monitoring frequency (Option 2a), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,123 per ton of methane reduced, and $925 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,040 per ton of VOC reduced, and $3,327 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $2,020 per ton VOC reduced, and $1,664 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $562 per ton methane reduced, and $462 per ton if natural gas savings are considered.

Under the single pollutant approach for the stepped monitoring frequency (Option 2b), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,340 per ton of methane reduced, and

$1,142 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,820 per ton of VOC reduced, and $4,107 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on stepped monitoring is $2,410 per ton VOC reduced, and $2,054 per ton if natural gas savings are considered. The control cost for methane based on semiannual to annual monitoring under the multipollutant approach is $670 per ton methane reduced, and $571 per ton if natural gas savings are considered.

For semiannual monitoring (Option 2c), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,771 per ton of methane reduced, and $1,573 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $6,372 per ton of VOC reduced, and $5,659 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $3,186 per ton VOC reduced, and $2,830 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $886 per ton methane reduced, and $787 per ton if natural gas savings are considered.

Finally for the biennial monitoring (Option 2e), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $791 per ton of methane reduced, and $593 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $2,847 per ton of VOC reduced, and $2,134 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on biennial monitoring is $1,423 per ton VOC reduced, and $1,067 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $396 per ton methane reduced, and $297 per ton if natural gas savings are considered.

Compressor Stations. For compressor stations, under the single pollutant approach for the annual monitoring frequency (Option 2a), if all costs are assigned to methane and zero to VOC reductions, the cost is $338 per ton of methane reduced, and $181 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $1,493 per ton of VOC reduced, and $798 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $746 per ton VOC reduced, and $399 per ton if natural gas savings are considered. The control cost for methane based on

annual monitoring under the multipollutant approach is $169 per ton methane reduced, and $90 per ton if natural gas savings are considered.

Under the single pollutant approach for semiannual monitoring (Option 2c), if all costs are assigned to methane and zero to VOC reductions, the cost is $519 per ton of methane reduced, and $362 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $2,292 per ton of VOC reduced, and $1,597 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $1,146 per ton VOC reduced, and $799 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $260 per ton methane reduced, and $181 per ton if natural gas savings are considered.

Finally for quarterly monitoring (Option 2d), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $864 per ton of methane reduced, and $706 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,813 per ton of VOC reduced, and $3,118 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on quarterly monitoring is $1,907 per ton VOC reduced, and $1,559 per ton if natural gas savings are considered. The control cost for methane based on quarterly monitoring under the multipollutant approach is $432 per ton methane reduced, and $353 per ton if natural gas savings are considered.

Because the gas handled by transmission and storage facilities is not typically owned by these facilities, we do not consider the value of the gas saved as an offset to the cost. However, for gathering and boosting stations, the gas savings could be considered. Therefore, we calculated the cost of control for compressor stations considering the gas savings contributed by gathering and boosting stations. This cost savings is reflected in the cost presented above and summarized in Table 2-23.

Table 2-23. Summary of the Cost of Control for the Method 21 Monitoring Options with a Repair Threshold of 500 ppm

Option	Cost of Control (without gas savings)				Cost of Control (with gas savings)			
	Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)		Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Non-Low Production Well Sites								
2a - Annual	$809	$2,909	$404	$1,453	$610	$2,196	$305	$1,096
2b - Stepped	$965	$3,471	$482	$1,735	$767	$2,758	$383	$1,379
2c - Semiannual	$1,275	$4,588	$638	$2,294	$1,077	$3,875	$539	$1,937
Low Production Well Sites								
2a - Annual	$1,123	$4,040	$562	$2,020	$925	$3,327	$462	$1,664
2b - Stepped	$1,340	$4,820	$670	$2,410	$1,142	$4,107	$571	$2,054
2c - Semiannual	$1,771	$6,372	$886	$3,186	$1,573	$5,659	$787	$2,830
2e – Biennial	$791	$2,847	$396	$1,423	$593	$2,134	$297	$1,067
Compressor Stations								
2a - Annual	$338	$1,493	$169	$746	$181	$798	$90	$399
2b - Semiannual	$519	$2,292	$260	$1,146	$362	$1,597	$181	$799
2d - Quarterly	$864	$3,813	$432	$1,907	$706	$3,118	$353	$1,559

2.5.1.3 Option 3 – Method 21 Monitoring with a 10,000 ppm Repair Threshold

Non-Low Production Well Sites. The same three sub-options used in sections 2.5.1.1 and 2.5.1.2 were evaluated for Method 21 monitoring with a 10,000 ppm repair threshold, Options 3a, 3b, and 3c. Under the single pollutant approach for the annual monitoring frequency (Option 3a), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,309 per ton of methane reduced, and $1,110 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,708 per ton of VOC reduced, and $3,995 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $2,354 per ton VOC reduced, and $1,997 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $654 per ton methane reduced, and $555 per ton if natural gas savings are considered.

Under the single pollutant approach for the stepped monitoring frequency (Option 3b), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,491 per ton of methane reduced, and $1,293 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $5,363 per ton of VOC reduced, and $4,650 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual to annual monitoring is $2,681 per ton VOC reduced, and $2,325 per ton if natural gas savings are considered. The control cost for methane based on semiannual to annual monitoring under the multipollutant approach is $745 per ton methane reduced, and $646 per ton if natural gas savings are considered.

Finally, for semiannual monitoring (Option 3c) of non-low production well sites, under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,755 per ton of methane reduced, and $1,557 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $6,313 per ton of VOC reduced, and $5,600 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $3,156 per ton VOC reduced, and $2,800 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $877 per ton methane reduced, and $778 per ton if natural gas savings are considered.

Low Production Well Sites. Similarly for low production well sites, under the single pollutant approach for the annual monitoring frequency (Option 3a), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,818 per ton of methane reduced, and $1,619 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $6,539 per ton of VOC reduced, and $5,826 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $3,269 per ton VOC reduced, and $2,913 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $909 per ton methane reduced, and $810 per ton if natural gas savings are considered.

Under the single pollutant approach for the stepped monitoring frequency (Option 3b), if all costs are assigned to methane and zero to VOC reductions, the cost is $2,071 per ton of methane reduced, and $1,872 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $7,449 per ton of VOC reduced, and $6,736 per ton of VOC reduced if savings

of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on stepped monitoring is $3,724 per ton VOC reduced, and $3,368 per ton if natural gas savings are considered. The control cost for methane based on semiannual to annual monitoring under the multipollutant approach is $1,035 per ton methane reduced, and $936 per ton if natural gas savings are considered.

Finally for semiannual monitoring (Option 3c), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $2,437 per ton of methane reduced, and $2,239 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $8,768 per ton of VOC reduced, and $8,055 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $4,384 per ton VOC reduced, and $4,027 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $1,219 per ton methane reduced, and $1,120 per ton if natural gas savings are considered.

Finally for the biennial monitoring (Option 3e), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,609 per ton of methane reduced, and $1,411 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $5,789 per ton of VOC reduced, and $5,076 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on biennial monitoring is $2,894 per ton VOC reduced, and $2,538 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $805 per ton methane reduced, and $705 per ton if natural gas savings are considered.

Compressor Stations. For compressor stations, under the single pollutant approach for the annual monitoring frequency (Option 3a), if all costs are assigned to methane and zero to VOC reductions, the cost is $547 per ton of methane reduced, and $390 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $2,416 per ton of VOC reduced, and $1,721 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $1,208 per ton VOC reduced, and $860 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $274 per ton methane reduced, and $195 per ton if natural gas savings are considered.

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Under the single pollutant approach for semiannual monitoring (Option 3c), if all costs are assigned to methane and zero to VOC reductions, the cost is $714 per ton of methane reduced, and $557 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,154 per ton of VOC reduced, and $2,459 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $1,577 per ton VOC reduced, and $1,229 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $357 per ton methane reduced, and $278 per ton if natural gas savings are considered.

Finally for quarterly monitoring (Option 3d), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,057 per ton of methane reduced, and $900 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,668 per ton of VOC reduced, and $3,973 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on quarterly monitoring is $2,334 per ton VOC reduced, and $1,986 per ton if natural gas savings are considered. The control cost for methane based on quarterly monitoring under the multipollutant approach is $529 per ton methane reduced, and $450 per ton if natural gas savings are considered.

Because the gas handled by transmission and storage facilities is not typically owned by these facilities, we do not consider the value of the gas saved as an offset to the cost. However, for gathering and boosting stations, the gas savings could be considered. Therefore, we calculated the cost of control for compressor stations considering the gas savings contributed by gathering and boosting stations. This cost savings is reflected in the cost presented above and summarized in Table 2-24.

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Table 2-24. Summary of the Cost of Control for the Method 21 Monitoring Options with a Repair Threshold of 10,000 ppm

Option	Cost of Control (without gas savings)				Cost of Control (with gas savings)			
	Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)		Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Non-Low Production Well Sites								
3a - Annual	$1,309	$4,708	$654	$2,354	$1,110	$3,995	$555	$1,997
3b - Stepped	$1,491	$5,363	$745	$2,681	$1,293	$4,650	$646	$2,325
3c - Semiannual	$1,755	$6,313	$877	$3,156	$1,557	$5,600	$778	$2,800
Low Production Well Sites								
3a - Annual	$1,818	$6,539	$909	$3,269	$1,619	$5,826	$810	$2,913
3b - Stepped	$2,071	$7,449	$1,035	$3,724	$1,872	$6,736	$936	$3,368
3c - Semiannual	$2,437	$8,768	$1,219	$4,384	$2,239	$8,055	$1,120	$4,027
3e – Biennial	$1,609	$5,789	$805	$2,894	$1,411	$5,076	$705	$2,538
Compressor Stations								
3a - Annual	$547	$2,416	$274	$1,208	$390	$1,721	$195	$860
3b - Semiannual	$714	$3,154	$357	$1,577	$557	$2,459	$278	$1,229
3d - Quarterly	$1,057	$4,668	$529	$2,334	$900	$3,973	$450	$1,986

2.6 Sensitivity Analysis

2.6.1 Fugitive Emissions Estimation of Percent Leaking

The EPA performed a sensitivity analysis on the estimates of components identified with fugitive emissions, herein referred to as the "percent leaking". This value is calculated by dividing the number of components identified with fugitive emissions by the total number of components monitored. In 2016, the EPA estimated that 1.18% of the fugitive emissions components would be identified as having fugitive emissions.[37] This value directly affects the repair costs that are estimated for the fugitive emissions

[37] The assumption of 1.18% leak rate for OGI monitoring was obtained from Table 5 of the Uniform Standards memorandum. The 1.18% value is the baseline leak frequency for valves in gas/vapor service. None of the other baseline frequencies in this table were used because the equipment are in liquid service (*e.g.*, pumps LL, valve LL, agitators LL). There is no information

requirements. For each of the model plants in this analysis, the 1.18% equates to 4 repairs at non-low production and low production well sites, 46 repairs at gathering and boosting stations, 45 repairs at transmission compressor stations, and 93 repairs at storage compressor stations.

The EPA received data from the American Petroleum Institute (API),[38] GPA Midstream (GPA),[39] and Target Emission Services (Target)[40] that includes the percent leaking based on fugitive emissions monitoring at well sites, gathering and boosting stations, and transmission compressor stations. The majority of this data was based on the use of OGI, however, there was some limited information from gathering and boosting stations on the use of Method 21. The EPA evaluated this data, though direct comparison with the EPA's model plant analysis was difficult due to several uncertainties which are discussed in detail in the memorandums in the docket.[41] It is important to note that since we utilize the average emissions factors, as discussed in section 2.3.5, the emissions are not affected by any changes in the percent leaking values used. Therefore, the only effect the percent leaking has on the cost of control is due to a change in the cost of repairs.

The information submitted by API was specific to initial monitoring at 4,117 well sites located throughout the United States in a variety of different basins.[42] The data included 1,521 single-wellhead gas sites, 755 multi-wellhead gas sites, 1,164 single-wellhead oil sites, and 677 multi-wellhead oil sites. The data represented the first monitoring survey for each site, and all monitoring surveys were conducted using OGI. API included an evaluation of the percent leaking for these well sites and concluded that the average initial percent leaking for all well sites was 0.4% of the components surveyed. The EPA performed a separate analysis of the raw data, and concluded the average initial percent leaking for that data set was 0.54%. Despite uncertainties associated with the data,[43] the EPA performed an analysis of the

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on the number of leaks located at uncontrolled facilities, only average percentages of the total number of components at a facility. Therefore, our methodology was to use the 1.18% leak frequency value from the Uniform Standards memorandum and apply that value to the total number of components at the oil and natural gas model plant. (Uniform Standards Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180).

[38] See memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 17, 2018.

[39] See memorandum *EPA Analysis of Compressor Station Fugitive Emissions Monitoring Data Provided by GPA Midstream* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 17, 2018.

[40] See memorandum *NSPS OOOOa Monitoring Case Study Presentation by Terence Trefiak with Target Emission Services* located at Docket ID No. EPA-HQ-OAR-2017-0483. March 13, 2018.

[41] See memorandums in footnotes 19, 20, and 21.

[42] The data represented well sites in Alaska, Arkansas, Colorado, Louisiana, Montana, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, Utah, West Virginia, and Wyoming.

[43] See memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 17, 2018.

cost of control using both the EPA's estimated value of 1.18% and the estimated 0.54% from EPA's evaluation of API's data. Table 2-25 summarizes the results of this analysis.

Table 2-25. Comparison of Cost of Control Options at Well Sites (without cost savings)

Option	Cost of Control (1.18% leaking)				Cost of Control (0.54% leaking)			
	Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)		Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Non-Low Production Well Sites								
1a - Annual	$979	$3,744	$490	$1,761	$961	$3,459	$481	$1,729
1b - Stepped	$1,041	$3,523	$520	$1,872	$1,021	$3,672	$510	$1,836
1c - Semiannual	$1,164	$4,186	$582	$2,093	$1,140	$4,100	$570	$2,050
Low Production Well Sites								
1a - Annual	$1,360	$4,893	$680	$2,446	$1,335	$4,804	$668	$2,402
1b - Stepped	$1,445	$5,200	$723	$2,600	$1,418	$5,101	$709	$2,550
1c - Semiannual	$1,616	$5,814	$808	$2,907	$1,583	$5,695	$792	$2,847

The data submitted by GPA consisted of 110 gathering and boosting compressor stations, located in Wyoming, Colorado, Ohio, Oklahoma, and Texas. OGI was used for monitoring at 104 of the gathering and boosting stations, and Method 21 was used at the remaining 6 gathering and boosting stations. Because of the differences in control effectiveness as presented in Table 2.14, the EPA estimated a percent leaking based on the OGI monitoring events separately from the Method 21 monitoring events. For the OGI data presented, the EPA calculated an average percent leaking of 0.47%. It is important to note that GPA submitted data that represented multiple monitoring events for each station, typically spanning several years. Therefore, the EPA also calculated an average percent leaking of 1.31% based on the maximum percent leaking reported for each station. The EPA performed 2 comparisons of the cost of control using the initial and average percent leaking values of 1.31% and 0.47%.

The data submitted by Target consisted of 104 transmission compressor stations, located in Oklahoma, Pennsylvania, Tennessee, Louisiana, Texas, Ohio, New York, South Carolina, and West Virginia. For 10 of these compressor stations, Target presented monitoring results that represented 4 consecutive quarters of monitoring under the requirements in the 2016 NSPS OOOOa. On average, Target reported 2.4 compressors per compressor station, with approximately 500-700 fugitive emissions

components per compressor located at the station. Using this information, the EPA estimated an average of 1,440 fugitive emissions components per transmission compressor station in the Target data set. The EPA then calculated the initial percent leaking as 0.71% for the 10 compressor stations presented in the information. The EPA then applied the 0.71% leaking to transmission and storage stations in the model plant analysis to compare the cost of control to that calculated using EPA's 1.18%. Additionally, for these 10 compressor stations, the EPA calculated an average percent leaking value of 0.43%. As presented in section 2.5, the EPA is presenting a comparion of the industry-based cost of control to EPA's estimated value as a weighted average across all compressor station subtypes, as presented in Tables 2-26 and 2-27.

Table 2-26. Comparison of Initial Monitoring Cost of Control Options at Compressor Stations (without cost savings)

Option	Cost of Control (1.18% leaking)				Cost of Control (1.31% leaking-0.71% leaking)[a]			
	Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)		Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Non-Low Production Well Sites								
1a - Annual	$557	$2,414	$278	$1,207	$569	$2,465	$284	$1,233
1c - Semiannual	$652	$2,827	$326	$1,413	$668	$2,895	$334	$1,448
1d - Quarterly	$910	$3,946	$455	$1,973	$934	$4,049	$467	$2,024

[a] The 1.31% value is applied to repairs at gathering and boosting stations. The 0.71% value is applied to repairs at transmission and storage stations.

Table 2-27. Comparison of Subsequent Monitoring Cost of Control Options at Compressor Stations (without cost savings)

Option	Cost of Control (1.18% leaking)				Cost of Control (0.47% leaking-0.43% leaking)[a]			
	Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)		Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Non-Low Production Well Sites								
1a - Annual	$557	$2,414	$278	$1,207	$396	$1,718	$198	$859
1c - Semiannual	$652	$2,827	$326	$1,413	$438	$1,899	$219	$950
1d - Quarterly	$910	$3,946	$455	$1,973	$589	$2,555	$295	$1,278

[a] The 0.47% value is applied to repairs at gathering and boosting stations. The 0.43% value is applied to repairs at transmission and storage stations.

VOLUME 2: NATIONAL LEVEL IMPACTS

3.0 NATIONWIDE IMPACTS FOR FUGITIVE EMISSIONS STANDARDS

3.1 Nationwide Costs and Emissions from Affected Sources

Similar to the approach used to calculate emissions, nationwide emissions were calculated by using the emissions calculated for the non-low production well site, low production well site, and compressor station model plants. These model plant emissions were used to estimate the baseline emissions, and the change in emissions for the sources affected by this reconsideration as a result of changing compliance activities. In this section we describe how we estimated the baseline emissions and costs, and incremental costs and emissions change related to a suite of alternative options. The incremental costs and emissions are the difference between the costs and emissions attributed to sources affected by this proposal from the baseline of costs and emissions.

3.2 Updated Baseline

The baseline used in this analysis represents our estimation of how the oil and natural gas industry looks today. This includes an estimate of the number of sources that are subject to the 2016 NSPS OOOOa using the same methods as were used in the 2016 NSPS analysis. A description of these methods is in the 2016 NSPS Final TSD and 2016 RIA. Where possible, we updated the information used, including sources of information, as described below. For well sites, we used an estimate of the number of oil and natural gas wells, along with a year by year rate of change in the number of new oil and natural gas wells to project the number of affected oil and natural gas wells from a base year, in this case 2014, through 2025. For gathering and boosting stations and transmission and storage facilities, we estimated an average number of new facilities per year.

3.2.1 Activity Data

Data from oil and natural gas technical documents and inventories, including previous TSDs for oil and gas actions, were used to estimate the number of new sources for each of the oil and natural gas segments. Information from the DrillingInfo HPDI® database and GHG Inventory were updated from the

2016 NSPS OOOOa analysis. DrillingInfo was used to estimate the number of new well sites in 2014, as explained in section 3.2.2. The GHG Inventory to update the equipment counts for well sites and gathering and boosting stations in 2014, as explained in section 2.3.2. While equipment counts for the transmission and storage stations were not updated for the model plants, we used the GHG Inventory to estimate the number of new gathering and boosting, transmission, and storage compressor stations, and other equipment in the transmission and storage segment, such as compressors and pneumatic controllers, as explained in section 3.2.3.

3.2.2 Number of Well Sites

The DrillingInfo database provided the information on the total number of oil and natural gas wells completed or recompleted in 2014 in the U.S. The base year of 2014 was chosen for two reasons. First, it predated the proposal for the 2016 NSPS OOOOa, therefore activity in that year was not affected by those requirements. Second, there is significant variation in how quickly information from all states is included in DrillingInfo data, resulting in potential data gaps if a year after 2014 was chosen. The DrillingInfo data includes information on GOR, location, and production. The EPA used this data to calculate the number of affected sources for each sub-type of model plant based on the GOR and initial production information, which characterized completion status, use of hydraulic fracturing, and location of the well. The GOR categories are gas wells (GOR greater than 100,000), oil with associated gas wells (GOR less than 100,000 and greater than 300), and heavy oil wells (GOR less than 300). Wells are categorized by GOR based on the total production in the base year (2014).

As described in section 2.3.2, the EPA evaluated the emission reductions and cost of control for low production well sites where the average combined oil and natural gas production is less than 15 boe per day averaged over the first 30 days of production separately from that of non-low production well sites. We used production information from the DrillingInfo data to categorize each affected well as low production (less than 15 boe per day production) or non-low production (greater than 15 boe per day production). These production levels were based on the initial production reported in DrillingInfo. The DrillingInfo field 'PRAC_IP_BOE' was used, which includes both liquid and gas production and is based on the second month production recorded for the well. The second month was used to represent practical initial production because the first month record may be a partial month depending on when production started. After estimating the number of new wells based on each subcategory and subtype that are subject to the 2016 NSPS OOOOa, we applied the same assumption of 2 wells per well site as used in the model plant analysis to obtain the number of each well site subject to the 2016 NSPS OOOOa.

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Additionally, the EPA published final amendments to the 2016 OOOOa rule on March 12, 2018 that created separate fugitives monitoring and repair requirements for well sites on the Alaskan North Slope.[44] In summary, these amendments granted additional time for initial monitoring during cold weather months, and required annual monitoring for these well sites. We used the location information from DrillingInfo to identify these well sites, and those in the states identified in section 3.2.2.1 subject to fugitive emissions standards under state regulations.

Table 3-1 shows the count of well sites in the base year (2014) for each model plant. In this table, wells are broken out into states of particular interest, including Alaska, California, Colorado and Texas.

Table 3-1. Well Completions in 2014 by Production Level and Well Type

Location	Non-low production wells			Low production wells		
	Natural Gas	Oil *(GOR >300)*	Oil *(GOR < 300)*	Natural Gas	Oil *(GOR >300)*	Oil *(GOR < 300)*
Alaska/North-Slope	2	59	2	0	4	0
Alaska/Other	14	6	1	6	1	0
California	9	298	575	2	133	581
Colorado	284	1,035	44	33	20	16
Louisiana	231	281	111	23	50	407
North Dakota	0	2,081	138	0	48	17
New Mexico	43	950	55	12	116	27
Ohio	169	290	10	71	97	134
Oklahoma	341	1,383	421	63	71	231
Pennsylvania	605	103	6	64	408	337
Texas	973	10,302	1,397	141	1,176	1,459
Utah	122	558	42	12	131	9
Wyoming	255	549	113	55	20	65
Other states	954	484	780	335	169	1,058

Source: DrillingInfo database extracted January 2018.[45]

We used the Energy Information Association's 2018 Annual Energy Outlook (AEO) projection of wells drilled in the contiguous 48 states to estimate a year by year rate of change from 2014 through 2025. We applied that year by year rate of change to the estimated number of wells in 2014 from DrillingInfo, regardless of well type, to project the estimated number of new well sites through 2025, scaled to the AEO oil and natural gas drilling activity projections. The estimated number of new or modified facilities using

[44] 83 FR 10628.

[45] Memorandum to Jameel Alsalam, EPA, Elizabeth Miller, EPA, and Melissa Weitz, EPA from Casey Pickering, ERG and Robyn Reid, ERG titled, *DI Desktop Data Processing Overview for OAP/OAQPS* located at Docket ID No. EPA-HQ-OAR-2017-0473. February 6, 2018.

this well-drilling based approach rises and falls in each projection year depending on projected oil and gas drilling activity from the AEO. This approach was used to support the regulatory impacts assessment process to reflect the 2016 NSPS OOOOa impacts from the effective date through 2025.

3.2.2.1 State Regulations that Address Fugitive Emissions at Well Sites

In the process of estimating fugitive emissions controls at well sites in the baseline and regulatory options, EPA accounted for wells that were assumed to be covered by state regulations. In cases where state regulations would achieve equal or greater controls as the 2016 NSPS OOOOa controls, the regulatory options in this reconsideration do not result in a change in applied controls. Based on our research, five states have enacted regulations we believe meet or exceed the 2016 NSPS OOOOa standard for fugitive emissions: California, Colorado, Ohio, Pennsylvania, and Utah. These states are broken out in Table 3-1 above, and consist of just over 18% of the total number of well sites in the base year (2014). Below is a brief discussion[46] of these state regulations:

- California: On July 17, 2017, the California Air Resources Board finalized fugitive emissions requirements for well sites.[47] Beginning January 1, 2018, owners and operators of well sites were required to conduct weekly auditory, visual, and olfactory (AVO) inspections and quarterly monitoring using Method 21. OGI is allowed as a screening tool. Operators are required to repair components with a Method 21 instrument reading of 10,000 ppm or greater. Beginning January 1, 2020, the requirements change such that components with a Method 21 instrument reading of 1,000 ppm or greater are subject to repair.

- Colorado: Colorado issued revisions to Regulation 7 effective October 15, 2014 and June 30, 2018.[48] Owners/operators are required to inspect components for leaks using an approved instrument monitoring method (AIMM). There are two sets of requirements: one for ozone nonattainment areas, and one for the rest of the state. The requirements are similar in that inspections are required at set frequencies using Method 21, an OGI camera, or other Division approved instrument based monitoring method or device, in addition to monthly AVO inspections. Inspection frequencies are based on the site-wide VOC emissions, such that for well sites in ozone nonattainment areas monitoring is either annual (1-6 tpy VOC) or semiannual (>6 tpy), and for the

[46] For more details about the individual state regulations as they relate to fugitive emissions requirements, see *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa* available at Docket ID No. EPA-HQ-OAR-2017-0483.
[47] California requirements available at https://www.arb.ca.gov/regact/2016/oilandgas2016/ogfro.pdf.
[48] Colorado regulations available at https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9_0.pdf.

rest of the state varying from one time inspections to annual inspections (*i.e.,* 0-6 tpy - one-time, 6-12 tpy -annually, 12-50 tpy -quarterly, or >50 tpy -monthly).

- Ohio: On May 19, 2014 Ohio EPA approved two types of General Permits for (1) oil and gas well-site production operations (small flares and large flares) and (2) high volume horizontal hydraulic fracturing. These General Permits are for facilities that emit less than 1 ton per year of any toxic air contaminant (not including hazardous air pollutants emitting sources that are subject to 40 CFR Part 63, Subpart HH). [49] Under the General Permits, operators are required to develop and implement a site-specific LDAR program for ancillary equipment (*e.g.,* vent, compressor, PRD, flange, etc.) that requires monitoring using OGI or Method 21. During the first year, quarterly monitoring is required, and the monitoring frequency varies based on performance in subsequent years.[50]

- Pennsylvania: On June 7, 2018, the Pennsylvania Department of Environmental Protection finalized a General Permit for unconventional oil and gas well sites. Under the General Permit, operators are required to conduct fugitives monitoring for various components (*e.g.,* vent, connectors, PRDs, OELs, etc.) using OGI or Method 21 at 500 ppm. Monitoring is required within 60 days of startup and quarterly thereafter.[51]

- Utah: On January 3, 2018, the Utah Department of Environmental Quality approved a Permit by Rule (PBR) for well sites that are not major sources as defined in Utah Administrative Code R. 307-101-2.[52] Beginning March 2, 2018, well sites where storage tank and dehydrator emissions are greater than 4 tpy VOC are required to conduct semiannual monitoring for fugitive emissions. The PBR requirements cover all components in the proposed technical reconsideration, with the exception of thief hatches and other openings on controlled storage vessels. Monitoring is required with OGI or Method 21 with a leak definition of 500 ppm.

It should be noted that even though the EPA considered the Wyoming regulations to be equivalent for the 2016 NSPS OOOOa RIA, it is no longer considered to be equivalent because the requirements only apply to the Upper Green River Basin, as opposed to the entire state. In addition, the EPA is

[49] EPA regulations available at https://www.ecfr.gov/cgi-bin/text-idx?node=sp40.11.63.hh.
[50] Ohio regulations available at http://www.epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf and http://epa.ohio.gov/dapc/genpermit/genpermits.aspx#127854016-available-permits.
[51] Pennsylvania regulations available at http://www.dep.pa.gov/Business/Air/BAQ/Permits/Pages/GeneralPermits.aspx
[52] Utah regulations are available at https://www.utah.gov/pmn/files/359797.pdf#page=2.

considering the Texas Standard Permit requirements to be equivalent to those in the proposed standard; however, most operators within the state are subject to the requirements of the permit by rule, which are not considered to be equivalent. Therefore, the EPA is not including the Texas regulations in the corresponding RIA analysis. Pennsylvania's General Permit 5 is considered to be equivalent to the rule; however, this permit only applies to compressor stations and will not be included in the RIA analysis because we do not currently have the data to separate compressor stations out by state.

3.2.3 Gathering and Boosting Stations and Transmission and Storage Compressor Stations

In addition to well sites, the fugitive emissions requirements apply to gathering and boosting stations, transmission compressor stations, and storage compressor stations. The GHG Inventory is used to estimate the count of newly affected compressor stations in each year. The GHG Inventory uses a variety of data sources and studies to estimate equipment counts and emissions. Many equipment counts are based on the data reported under the GHGRP, scaled up to reflect the total population including both GHGRP-reporting and non-reporting oil and natural gas facilities.

We estimated the number of new compressor stations, by type, by averaging the increases in the year-to-year changes in total national counts of equipment over the 10-year period from 2004 through 2014. Year-to-year increases were assumed to represent newly constructed facilities. Decreases in total counts were represented as zeros for that year, and average together with the annual increases. This approach results in the same number of new compressor stations in each projected year, regardless of increases or decreases in AEO projected drilling or production. These values reflect that construction of compressor stations and transmission pipelines are longer-term investments not necessarily correlated with short-term fluctuations in production. In addition, this approach may result in fewer total new and modified compressor stations for two reasons: (1) modifications of existing compressor stations are not captured, and (2) if existing compressor stations are closed and replaced with new facilities, those would not be reflected in the net increase in the year-to-year total. The national equipment counts estimated in the GHG Inventory are not disaggregated by state, therefore, activity data using this approach is only estimated at the national level. The average year-to-year increase for compressor stations is summarized in Table 3-2.

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Table 3-2. Average Year-to-Year Increases in Compressor Station Counts

Location	Average Year-to-Year Increase
Gathering and Boosting Stations	212
Transmission Compressor Stations	36
Storage Compressor Stations	2

3.2.4 Baseline Emission Estimates

The nationwide baseline emissions were calculated using the model plant data and the estimated number of new and modified sources for each of the segments, as explained above. The baseline nationwide emissions were estimated assuming all 2016 NSPS OOOOa sources are complying with that regulation. The nationwide emission estimates for the total number of oil and natural gas production well sites, gathering and boosting stations, and transmission and storage facilities that we estimate are complying with the fugitive emission requirements in the 2016 NSPS OOOOa are summarized in Table 3-3. The summary includes baseline emissions for each of these segments for projected year 2025, assuming no changes to the standards already in place.

Table 3-3. Nationwide Baseline Emissions for Sources Subject to Fugitive Emissions Monitoring in Year 2025

Oil and Gas Segment	Number of Sources Subject to NSPS[a]	Methane Emissions (tpy)	VOC Emissions (tpy)
Non-Low Production Well Sites	**79,616**	**102,852**	**28,590**
Natural Gas Well Sites	12,219	26,687	7,418
Oil Well Sites (GOR > 300)	56,115	67,612	18,794
Oil Well Sites (GOR < 300)	11,282	8,553	2,377
Low Production Well Sites	**23,211**	**20,257**	**5,631**
Natural Gas Well Sites	2,494	4,599	1,278
Oil Well Sites (GOR > 300)	7,462	6,990	1,943
Oil Well Sites (GOR < 300)	13,254	8,668	2,409
Compressor Stations	**2,750**	**20,216**	**4,662**
Gathering & Boosting Stations	2,332	16,390	4,556
Transmission Stations	396	3,199	89
Storage Stations	22	627	17

a. Affected facilities in 2025 includes new affected facilities in 2015 through 2025 which are assumed to still be operating in 2025.

3.3 Nationwide Incremental Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (*i.e.*, increase in emissions), cost impacts, and secondary environmental impacts related to the regulatory options which were selected as a viable options for reducing fugitive emissions from fugitive emissions components located at well sites and compressor stations under this proposed reconsideration.

Based on the discussion above, the EPA reconsidered Regulatory Options 1a, 1b and 1c for well sites and Regulatory Options 1a, 1c, and 1d for compressor stations. A summary of the options is provided below. While we also evaluated Regulatory Option 2 (Method 21 monitoring), we are not presenting nationwide impacts of that option because Regulatory Option 1 (OGI monitoring) was selected as the BSER for the collection of fugitive emissions components located at well sites and compressor stations.

- Regulatory Option 1: The implementation of a fugitive emissions monitoring and repair program using OGI as the detection method. The following sub-options were evaluated for different monitoring frequencies, as shown below.

- 1a. Monitoring on an annual frequency at well sites and compressor stations.
- 1b. Monitoring on a semiannual frequency for 2 years, followed by annual monitoring thereafter at well sites.
- 1c. Monitoring on a semiannual frequency at well sites and compressor stations.
- 1d. Monitoring on a quarterly frequency at compressor stations.
- 1e. Monitoring on a biennial frequency at low production well sites.

The impacts of this reconsideration are based on the number of sources affected by this reconsideration for each option compared to the baseline of the 2016 NSPS OOOOa. The number of sources affected by this reconsideration varies across the options. For example, oil and natural gas well sites outside of the Alaskan North Slope are unaffected when regulatory option 1c is being considered as they are already required to follow the semiannual fugitive emissions monitoring and repair program, however they are affected sources under Regulatory Options 1a, and 1b. The number of oil and natural gas well sites, gathering and boosting stations, transmission stations, and storage facilities that would be subject to each of the regulatory options listed above were estimated using the same method as outlined for the baseline of affected sources as described above; namely data from the DrillingInfo database, the 2018 AEO, and the 2018 GHG Inventory. In 2025, which include all new and modified sources since 2016, it was estimated that there would be at most 12,219 natural gas well sites, 11,282 oil well sites with GOR <300, and 56,115 oil well sites with GOR >300 for non-low production well sites; 2,494 natural gas well sites, 13,254 oil well sites with GOR <300, and 7,462 oil well sites with GOR >300 for low production well sites; 2,332 gathering and boosting stations, 396 transmission stations, and 22 storage facilities subject to these options.

3.3.1 Primary Environmental Impacts of Regulatory Options as a Change from the Baseline

As described in section 2.4.1.2, we estimated that a fugitive emissions monitoring and repair program can achieve an overall 30 percent reduction in VOC and methane emissions at a biennial monitoring frequency, 40 percent reduction at an annual monitoring frequency, 45 percent reduction at a stepped monitoring frequency, 60 percent reduction at a semiannual monitoring frequency, and 80 percent reduction at a quarterly monitoring frequency. Nationwide emission reductions were estimated by applying these same percentages to the uncontrolled baseline emissions for well sites and compressor stations at the various frequencies.

To illustrate the effects of the options, we provide the forgone emission reductions (or the increase in emissions) for each of the options. There are forgone emission reductions because options 1a, 1b, and

1e are less frequent than the baseline monitoring frequency for well sites, and options 1a and 1c are less frequent than the baseline monitoring frequency for compressor stations. Table 3-4 summarizes the forgone emission reductions for the options with less frequent monitoring than the baseline.

Table 3-4. Nationwide Forgone Emission Reductions for Sources Subject to Fugitive Emissions Monitoring in Year 2025

Oil and Gas Segment	Methane Emissions (tpy)	VOC Emissions (tpy)
Non-Low Production Well Sites		
Option 1a – Annual	43,708	12,150
Option 1b - Stepped	32,781	9,113
Option 1c – Semiannual[a]	--	--
Low Production Well Sites		
Option 1a – Annual	8,158	2,268
Option 1b - Stepped	6,119	1,701
Option 1c – Semiannual[a]	--	--
Option 1e – Biennial	12,242	3,403
Compressor Stations		
Option 1a – Annual	40,432	9,324
Option 1c - Semiannual	20,216	4,662
Option 1d – Quarterly[a]	--	--

a. Options 1c and 1d are the same as the baseline for well sites and compressor stations, respectively, therefore, forgone emission reductions are not applicable to these monitoring frequencies.

3.3.2 Natural Gas Savings as a Change from the Baseline

The implementation of a fugitive emissions monitoring and repair program will result in savings of natural gas, which can offset compliance costs. The change in natural gas savings for each of the OGI monitoring options was evaluated for this reconsideration as described below. We are not presenting this information for Options 2 or 3 because Method 21 is an alternative to OGI monitoring in this reconsideration.

OGI Monitoring. The various monitoring frequencies under Regulatory Option 1 (OGI monitoring) were evaluated to determine the change in natural gas savings from each monitoring frequency. In 2025, under Option 1a, annual monitoring, the potential natural gas saved at non-low

production well sites was calculated to decrease by 588,119 standard cubic feet per year (scf/yr) for natural gas production well sites, 1.7 million scf/yr for oil well sites with a GOR <300, and 219,478 scf/yr for oil well sites with a GOR >300. Similarly, for low production well sites, the natural gas saved under an annual monitoring frequency in 2025 was calculated to decrease by 107,927 scf/yr for natural gas production well sites, 211,179 scf/yr for oil well sites with a GOR <300, and 153,717 scf/yr for oil well sites with a GOR >300. For the compressor stations, the potential natural gas saved in 2025 was calculated to decrease by 1.9 million scf/yr for gathering and boosting stations, 331,222 Mscf/yr for transmission stations, and 64,891 Mscf/yr for storage facilities.[53]

Under Option 1b, semiannual monitoring for 2 years followed by annual monitoring, the potential natural gas saved in 2025 at non-low production well sites was calculated to decrease by 441,089 scf/yr for natural gas production well sites, 1.3 million scf/yr for oil well sites with a GOR <300, and 164,608 scf/yr for oil well sites with a GOR >300. Similarly, for low production well sites, the natural gas saved in 2025 under the stepped monitoring frequency was calculated to decrease by 80,945 scf/yr for natural gas production well sites, 158,384 scf/yr for oil well sites with a GOR <300, and 115,288 scf/yr for oil well sites with a GOR >300. We did not evaluate the stepped monitoring frequency for compressor stations as part of this reconsideration.

Under Option 1c, semiannual monitoring, we did not evaluate the change in the natural gas saved for well sites, as they perform semiannual monitoring under the baseline. For the compressor stations, the potential natural gas saved in 2025 was calculated to decrease by 949,865 scf/yr for gathering and boosting stations, 165,611 scf/yr for transmission stations, and 32,446 scf/yr for storage facilities.

Under Option 1d, quarterly monitoring, we did not evaluate a change in the natural gas saved, because compressor stations perform quarterly monitoring under the baseline, and we did not evaluate the quarterly monitoring frequency for non-low production well sites or low production well sites as part of this reconsideration.

Finally, under Option 1e, biennial monitoring, the potential natural gas saved in 2025 at low production well sites was calculated to decrease by 161,890 scf/yr for natural gas production well sites, 316,768 scf/yr for oil well sites with a GOR <300, and 230,762 scf/yr for oil well sites with a GOR >300.

[53] Natural gas savings calculated using the methane reductions and assuming a methane to natural gas volume ration of 82.9% for upstream facilities (well sites, gathering & boosting) and a methane to natural gas volume ratio of 92.8% for downstream facilities (transmission, storage).

We did not evaluate the biennial monitoring frequency for non-low production well sites or compressor stations as part of this reconsideration.

Operators in the transmission and storage segments of the industry typically do not own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, the unit-level cost and emission reduction analyses supporting BSER decisions in the preamble (and is presented in Volume 1 of the TSD) do not include estimates of revenue from natural gas recovery as offsets to compliance costs. From a social perspective, however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in the national impacts analysis. An economic argument can be made that, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the most simple and transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of these revenues across agents. This is the approach followed in Volume 2 of the TSD, as well as in the RIA.

To estimate the value of the natural gas saved, we used the AEO's projection of the price of natural gas. The AEO projects Henry Hub natural gas prices in $/MMBtu in 2017 dollars.[54] We adjust those prices to $/Mcf (using the conversion of 1 MMBtu = 1.028 Mcf) in 2016 dollars (using the GDP-Implicit Price Deflator) at the wellhead.[55] For example, the AEO Henry Hub price for natural gas is projects to be $4.07/MMBtu in 2017$ in 2025. After adjustments, the value for natural gas that we used for 2025 was $2.70/Mcf.

[54] Available at: http://www.eia.gov/forecasts/aeo/tables_ref.cfm.
[55] An EIA study indicated that the Henry Hub price is, on average, about 11 percent higher than the wellhead price. See http://www.eia.gov/oiaf/analysispaper/henryhub/.

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3.3.3 Cost Impacts as a Change from the Baseline

Similar to the discussion in sections 2.4.1.3, 2.4.2.3, and 2.5, we applied the regulatory cost of the rule for the model plants to the total predicted number of sources nationwide to estimate the total cost impacts of the fugitive emissions requirements. These costs include the capital costs or initial costs of the requirements (*e.g.,* initial setup of the monitoring plan, initial notification, and initial monitoring costs) and annual costs of the requirements (*e.g.,* subsequent monitoring event planning, conducting subsequent monitoring, repairs, and submission of annual reports). Additionally, we have taken into account the value of the saved natural gas, as discussed in section 3.3.2 and section 2.4.1. Tables 3-5a through 3-5d summarize the change in the nationwide cost impacts and forgone emission reductions for each of the OGI monitoring frequencies in Regulatory Option 1, compared to the baseline, for the year 2025. Similar information for other years that were evaluated is included as Attachment 1 to this document.

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Table 3-5a. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Projected Year 2025						
Non-Low Production Well Sites	**79,616**	**66,752**	**43,708**	**12,150**	**$68.36**	**$58.99**
Gas Well Sites	12,219	8,583	10,148	2,821	$8.79	$6.61
Oil Well Sites (GOR > 300)	56,115	48,961	29,773	8,276	$50.14	$43.76
Oil Well Sites (GOR < 300)	11,282	9,208	3,787	1,053	$9.43	$8.62
Low Production Well Sites	**23,210**	**16,946**	**8,158**	**2,268**	**$17.35**	**$15.60**
Gas Well Sites	2,494	1,939	1,862	518	$1.99	$1.59
Oil Well Sites (GOR > 300)	7,462	5,041	2,652	737	$5.16	$4.59
Oil Well Sites (GOR < 300)	13,254	9,966	3,644	1,013	$10.21	$9.42
Well Sites Total	**102,826**	**83,698**	**51,866**	**14,418**	**$85.71**	**$74.59**
Compressor Stations						
Gathering & Boosting	2,332	2,332	32,781	9,112	$43.18	$36.15
Transmission	396	396	6,398	177	$7.23	$6.01
Storage	22	22	1,253	35	$0.67	$0.43
Compressor Stations Total	**2,750**	**2,750**	**40,432**	**9,324**	**$51.08**	**$42.59**

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Table 3-5b. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Projected Year 2025						
Non-Low Production Well Sites	**79,616**	**66,752**	**32,781**	**9,113**	**$51.27**	**$44.24**
Gas Well Sites	12,219	8,583	7,611	2,116	$6.59	$4.96
Oil Well Sites (GOR > 300)	56,115	48,961	22,330	6,207	$37.60	$32.82
Oil Well Sites (GOR < 300)	11,282	9,208	2,840	790	$7.07	$6.46
Low Production Well Sites	**23,210**	**16,946**	**6,119**	**1,701**	**$13.01**	**$11.70**
Gas Well Sites	2,494	1,939	1,397	388	$1.49	$1.19
Oil Well Sites (GOR > 300)	7,462	5,041	1,989	553	$3.87	$3.45
Oil Well Sites (GOR < 300)	13,254	9,966	2,733	760	$7.65	$7.07
Well Sites Total	**102,826**	**83,698**	**38,900**	**10,814**	**$64.28**	**$55.94**

Table 3-5c. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Projected Year 2025						
Non-Low Production Well Sites	**79,616**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	12,219	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	56,115	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	11,282	0	0	0	$0.00	$0.00
Low Production Well Sites	**23,210**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	2,494	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	7,462	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	13,254	0	0	0	$0.00	$0.00
Well Sites Total	**102,826**	**0**	**0**	**0**	**$0.00**	**$0.00**
Compressor Stations						
Gathering & Boosting	2,332	2,332	16,390	4,556	$28.79	$25.27
Transmission	396	396	3,199	89	$4.82	$4.21
Storage	22	22	627	17	$0.45	$0.33
Compressor Stations Total	**2,750**	**2,750**	**20,216**	**4,662**	**$34.06**	**$29.81**

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Table 3-5d. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Projected Year 2025						
Compressor Stations						
Gathering & Boosting	2,332	0	0	0	$0.00	$0.00
Transmission	396	0	0	0	$0.00	$0.00
Storage	22	0	0	0	$0.00	$0.00
Compressor Stations Total	**2,750**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table 3-5e. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Projected Year 2025						
Low Production Well Sites	**23,210**	**16,958**	**12,242**	**3,403**	**$26.04**	**$23.41**
Gas Well Sites	2,494	1,939	2,794	777	$2.98	$2.38
Oil Well Sites (GOR > 300)	7,462	5,053	3,982	1,107	$7.75	$6.90
Oil Well Sites (GOR < 300)	13,254	9,966	5,466	1,519	$15.31	$14.14

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4.0 NATIONWIDE IMPACTS FOR CERTIFICATIONS

4.1 Nationwide Impacts of Regulatory Options

4.1.1 Approach

Nationwide impacts of certifications for closed vent system design and technical infeasibility of routing pneumatic pumps to an existing control device were calculated by estimating the count of affected facilities installed in a typical year and multiplying by the estimated cost per certification. Closed vent system and technical infeasibility certifications impact pneumatic pumps, centrifugal compressors, reciprocating compressors, and storage vessels. Unit level emissions and control cost estimates are unchanged in this action, and can be found in the 2016 NSPS Final TSD.[56]

4.1.2 Nationwide Activity Data for Equipment Requiring Certifications

4.1.2.1 Pneumatic Pumps and Compressors

The count of new pneumatic pumps and compressors installed in a typical year was estimated by determining the rate of change in the count of each source based on a review of the annual count of each source from the year 2005 through 2016 as reported in the 2018 GHG Inventory for natural gas and oil production facilities. The EPA used the same methodology in this analysis as is discussed in section 3.2.3 above. Namely, that typical new sources estimated by averaging increases in year-to-year changes in the total national counts of equipment over the 10-year period from 2005 to 2016, where a decrease is represented with a zero value.

The EPA has carried forward several assumptions from the 2016 NSPS Final TSD, including: (1) 50 percent of the pumps to be diaphragm and 50 percent of the pumps to be piston pumps, which are not affected facilities under the 2016 NSPS OOOOa; (2) no pneumatic pumps are used in the natural gas processing, natural gas transmission and storage segments; and (3) 75 percent of the new pumps will be able to be connect to an existing control device or process, and therefore will require a closed vent system design certification. In addition, we estimate that half of the remaining uncontrolled pneumatic pump affected facilities require additional certification

[56] See Docket ID No. EPA-HQ-OAR-2010-0505-7631.

for technical infeasibility of routing emissions to an existing control device, and the remaining half are uncontrolled because no control device is present. Therefore, we estimate an additional 12.5 percent of pneumatic pumps require a certification for technical infeasibility. The average number of new pneumatic pumps per year estimated from the 2018 GHG Inventory is about 4,336. Using the assumptions above, the average number certifications related to pneumatic pumps is 3,794. The results of this analysis are shown in Table 4-1.

The 2016 NSPS OOOOa requires closed vent system certification for all centrifugal compressor affected facilities, therefore, we assume 100 percent of these sources require certification. The average number of new centrifugal compressors from the GHGI is estimated to be 18 per year. The 2016 NSPS OOOOa allows an option for reciprocating compressor affected facilities to route emissions to a process; therefore, we estimate 10 percent of the reciprocating compressor affected facilities require a certification. The average number of new reciprocating compressors from the GHG Inventory is estimated to be 76 per year. Under that 10 percent assumption above, we estimated an average of 8 certifications related to centrifugal compressors per year. Table 4-1 presents the estimated counts of certification on pneumatic pumps and compressors in a typical year.

Table 4-1. Estimated Count of Certifications by Source in a Typical Year

Source	Count of Certifications
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Total	3,820

4.1.2.2 Storage Vessels

The methodology to determine the number of affected closed vent systems on storage vessels that are subject to certification requirements under the 2016 NSPS OOOOa closely follows the procedure used to estimate the number of storage vessels subject to the 2012 NSPS OOOO.[57] For the analysis performed during this reconsideration, we updated the data set by

[57] See memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. "Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector". April 2013. Docket ID No. EPA-HQ-OAR-2010-0505-4597.

updating the base year, and did not reduce the count of storage vessels controlled under existing state regulations, as there are no closed vent system certification requirements in existing regulations. The steps below were used to determine the number of storage vessels subject to the closed vent system certification requirements.

Step 1: Develop a dataset of newly completed wells in 2014

This analysis assumes that there is one new storage vessel with a closed vent system requiring certification per new well completed. The 2014 DrillingInfo data extraction, which includes production levels, location, and year the well was completed was used to assemble a dataset of wells completed in 2014. To do so, we followed the same process as described in section 3.2.2.

Step 2: Distribute the wells across production rate brackets

We then separated the wells into subcategories based on the production levels and calculated the boe per day from each well. Next we further separated the wells within each subcategory based on the subtype of well (*i.e.,* natural gas well and oil well). Using the boe for each well, we distributed the wells across the production brackets as shown in Table 4-4. This provides the estimated number of crude oil storage vessels (from oil wells) and condensate storage vessels (from natural gas wells) in each production bracket.

Step 3: Estimate emissions from a typical storage vessel within each production bracket

Average storage vessel emissions factors, in terms of mass of emissions per throughput, were developed in support of the 2012 NSPS OOOO.[58] These emissions factors were developed using the American Petroleum Institute's (API's) E&P Tanks program and more than 100 storage vessels across the country with varying characteristics.[59]

Uncontrolled VOC Emissions from Crude Oil Storage Vessels = 0.214 tpy VOC bbl/day

[58] U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for Proposed Standards. April 2012. Docket ID EPA-HQ-OAR-2010-0505-4550.
[59] Production Tank Emissions Model. E&P Tank Version 2.0. A Program for Estimating Emissions from Hydrocarbon Production Tanks. American Petroleum Institute. Software Number 4697. April 2000.

Uncontrolled VOC Emissions from Condensate Storage Vessels = 2.09 tpy VOC/bbl/day

To estimate the emissions from an average storage vessel within each production rate bracket, we developed average production rates for each bracket using EIA published nationwide production per well per day for each production bracket from 2006 through 2009.[60] Table 4-4 presents the average oil production and condensate production in barrels per well per day, respectively. For this analysis, we considered the liquid produced from oil wells to be crude oil and from gas wells to be condensate.

The average VOC emissions for each new storage vessel within each production rate bracket were calculated by applying the average production rate (bbl/day) to the VOC emission factor (tpy VOC/bbl/day) and are presented in Table 4-2.

Table 4-2. Average Oil and Condensate Production and Storage Vessel Emissions per Production Rate Bracket[61]

Production Rate Bracket (boe/day)[a]	Oil Wells		Gas Wells	
	Average Oil Production Rate per Oil Well (bbl/day)[b]	Crude Oil Storage Vessel VOC Emissions (tpy)[c]	Average Condensate Production Rate per Gas Well (bbl/day)[b]	Condensate Storage Vessel VOC Emissions (tpy)[c]
0- 1	0.385	0.083	0.0183	0.038
1- 2	1.34	0.287	0.0802	0.168
2- 4	2.66	0.570	0.152	0.318
4- 6	4.45	0.953	0.274	0.573
6- 8	6.22	1.33	0.394	0.825
8- 10	8.08	1.73	0.499	1.04
10- 12	9.83	2.11	0.655	1.37
12- 15	12.1	2.59	0.733	1.53
15- 20	15.4	3.31	1.00	2.10
20- 25	19.9	4.27	1.59	3.32

[60] Memorandum. Heather Brown, EC/R Incorporated to Bruce Moore, EPA/OAQPS/SPPD/FIG. Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector. April 8, 2013.
[61] Ibid.

Production Rate Bracket (boe/day)[a]	Oil Wells		Gas Wells	
	Average Oil Production Rate per Oil Well (bbl/day)[b]	Crude Oil Storage Vessel VOC Emissions (tpy)[c]	Average Condensate Production Rate per Gas Well (bbl/day)[b]	Condensate Storage Vessel VOC Emissions (tpy)[c]
25- 30	24.3	5.22	1.84	3.85
30- 40	30.5	6.54	2.55	5.33
40- 50	39.2	8.41	3.63	7.59
50- 100	61.6	13.2	5.60	11.7
100- 200	120	25.6	12.1	25.4
200- 400	238	51.0	23.8	49.8
400- 800	456	97.7	44.1	92.3
800- 1,600	914	196	67.9	142
1,600- 3,200	1,692	363	148	311
3,200- 6,400	3,353	719	234	490
6,400- 12,800	6,825	1,464	891	1,864
> 12,800[d]	0	0	0	0

Minor discrepancies may be due to rounding.
[a]boe=Barrels of Oil Equivalent
[b]Oil and condensate production rates published by EIA. "US Total Distribution of Wells by Production Rate Bracket." http://www.eia.doe.gov/pub/oil_gas/petrosystem/us_table.html.
[c]Oil storage vessel VOC emission factor = 0.214 tpy VOC/bbl/day. Condensate storage vessel VOC emission factor = 2.09 tpy/bbl/day.

Step 4: **Determine the number of storage vessels that would likely have uncontrolled VOC emissions greater than the NSPS applicability threshold of 6 tpy**

The next step was to determine the number of storage vessels that would potentially be subject to the NSPS by having VOC emissions greater than 6 tpy. As shown in Table 4-2, crude oil storage vessels in the production rate bracket of 30 to 40 boe per day and higher have average emissions greater than 6 tpy, meaning these storage vessels would be potentially subject to the NSPS. Similarly, condensate storage vessels in the production bracket of 40 to 50 boe per day and higher have emissions greater than 6 tpy.

Step 5: Project base count of storage vessels in 2014 through to 2025

The above steps were used to estimate the number of new storage vessels in 2014. Similar to the procedure used to determine the number of new storage vessels in 2014 based on the number of new wells in 2014 in DrillingInfo, we assumed that each new well drilled is associated with a new storage vessel. As in the projection of new wells, we use the AEO projection of drilling activity to determine a year-by-year rate of change and apply that rate of change to the number of new storage vessels. We used the AEO projection of wells drilled in the contiguous 48 states to estimate a year-by-year rate of change from 2014 through 2025. We applied that year-by-year rate of change to the estimated number of wells in 2014 from DrillingInfo, regardless of well type, to project the estimated number of new well sites through 2025, scaled to the AEO oil and natural gas drilling activity projections.

The 2016 NSPS OOOOa requires closed vent system certification for all storage vessel affected facilities, therefore we assume 100 percent of these sources require certification. The results of this analysis are shown in Table 4-3.

Table 4-3. Estimated Count of Storage Vessels Installed

Year	Count of SV that Require CVS Certification Under NSPS
2019	9,597
2020	10,375
2021	10,762
2022	11,123
2023	11,413
2024	11,591
2025	11,636

4.1.2.3 Summary of Affected Facilities Requiring Certification

Table 4-4 summarizes the count of the facilities in 2025 that are affected by this reconsideration that require certification under the 2016 NSPS OOOOa in the year 2025. This information is available for years 2019 through 2025 in Attachment 2 of this TSD.

Table 4-4. Estimated Count of Affected Facilities Requiring Certifications for 2025

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	11,636
Total	15,456

4.1.3 Nationwide Cost Impacts of Selected Regulatory Options

The EPA calculated the nationwide impacts of the reconsideration proposal to allow certifications to be done by either an in-house engineer or a professional engineer. EPA estimated that the cost for a PE certification is $546.66 per certification, and the cost for an in-house engineer certification is $358.09 per certification (in 2016$). This analysis assumes a PE certification requires 4 hours of staff engineering work, and 2 hours of PE work, and an in-house certification requires 4 hours of staff engineering work. We estimate wages for staff engineers based on estimates from the Bureau of Labor Statistics, Occupational Employment Statistics,[62] and inflate wages by 5 percent for PEs, based on 2010 survey findings from the National Society of Professional Engineers.[63] We have increased wages for both staff engineers and PEs by 110 percent to account for the benefit packages available to those employed by private industry.

Table 4-5, below, shows the estimated number of sources and the estimated national costs of PE certification, as under the 2016 NSPS OOOOa, and the estimated national costs of certification by in-house engineers, as being proposed in the reconsideration, in 2025. This information is available for years 2019 through 2025 in Attachment 2 of this TSD.

[62] Mean hourly wages, Industrial Engineers, Including Health and Safety ($42.63 per hour). May 2016 National Occupational Employment and Wage Estimates, United States. https://www.bls.gov/oes/current/oes_nat.htm#17-0000.

[63] 2010 survey findings from the National Society of Professional Engineers, https://www.nspe.org/resources/press-room/press-releases/engineering-salaries-continue-rise-despite-concern-over.

Table 4-5. Summary of National Level Impact for PE Certification Alternatives in 2025

Certification Costs - 2025	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	15,456	$8,449,280
Cost Estimate for Proposed Reconsideration	15,456	$5,534,706
Reduced Burden of Proposed In-House Engineer Certification	15,456	$2,914,573

Attachment 1

Supporting Information for Nationwide Impacts of the Fugitive Emissions Requirements

Table A1-1a. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2019						
Non-Low Production Well Sites	**32,720**	**27,433**	**17,963**	**4,993**	**$28.09**	**$24.88**
Gas Well Sites	5,022	3,527	4,171	1,159	$3.61	$2.87
Oil Well Sites (GOR > 300)	23,062	20,122	12,236	3,401	$20.61	$18.41
Oil Well Sites (GOR < 300)	4,636	3,784	1,556	433	$3.88	$3.60
Low Production Well Sites	**9,539**	**6,965**	**3,353**	**932**	**$7.13**	**$6.53**
Gas Well Sites	1,025	797	765	213	$0.82	$0.68
Oil Well Sites (GOR > 300)	3,067	2,072	1,090	303	$2.12	$1.93
Oil Well Sites (GOR < 300)	5,447	4,096	1,498	416	$4.19	$3.93
Well Sites Total	**42,259**	**34,398**	**21,316**	**5,925**	**$35.23**	**$31.41**
Gathering & Boosting	1,060	1,060	14,900	4,142	$19.63	$16.96
Transmission	180	180	2,908	81	$3.29	$2.82
Storage	10	10	570	16	$0.30	$0.21
Compressor Stations Total	**1,250**	**1,250**	**18,378**	**4,239**	**$23.22**	**$20.00**

Table A1-1b. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2020						
Non-Low Production Well Sites	**39,993**	**33,531**	**21,956**	**6,103**	**$34.34**	**$30.06**
Gas Well Sites	6,138	4,311	5,098	1,417	$4.41	$3.42
Oil Well Sites (GOR > 300)	28,188	24,594	14,956	4,157	$25.19	$22.27
Oil Well Sites (GOR < 300)	5,667	4,626	1,902	529	$4.74	$4.37
Low Production Well Sites	**11,659**	**8,512**	**4,097**	**1,139**	**$8.72**	**$7.92**
Gas Well Sites	1,253	974	935	260	$1.00	$0.82
Oil Well Sites (GOR > 300)	3,748	2,532	1,332	370	$2.59	$2.33
Oil Well Sites (GOR < 300)	6,658	5,006	1,830	509	$5.13	$4.77
Well Sites Total	**51,652**	**42,043**	**26,053**	**7,242**	**$43.06**	**$37.98**
Gathering & Boosting	1,272	1,272	17,881	4,970	$23.55	$20.07
Transmission	216	216	3,490	97	$3.95	$3.34
Storage	12	12	684	19	$0.36	$0.25
Compressor Stations Total	**1,500**	**1,500**	**22,055**	**5,086**	**$27.86**	**$23.66**

Table A1-1c. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2021						
Non-Low Production Well Sites	**47,537**	**39,857**	**26,097**	**7,255**	**$40.82**	**$35.78**
Gas Well Sites	7,296	5,125	6,059	1,684	$5.25	$4.08
Oil Well Sites (GOR > 300)	33,505	29,234	17,777	4,942	$29.94	$26.51
Oil Well Sites (GOR < 300)	6,736	5,498	2,261	629	$5.63	$5.19
Low Production Well Sites	**13,858**	**10,118**	**4,872**	**1,354**	**$10.36**	**$9.42**
Gas Well Sites	1,489	1,158	1,112	309	$1.19	$0.97
Oil Well Sites (GOR > 300)	4,455	3,010	1,584	440	$3.08	$2.78
Oil Well Sites (GOR < 300)	7,914	5,950	2,176	605	$6.09	$5.67
Well Sites Total	**61,395**	**49,975**	**30,969**	**8,609**	**$51.18**	**$45.20**
Gathering & Boosting	1,484	1,484	20,861	5,799	$27.48	$23.45
Transmission	252	252	4,071	113	$4.60	$3.90
Storage	14	14	798	22	$0.43	$0.29
Compressor Stations Total	**1,750**	**1,750**	**25,730**	**5,934**	**$32.51**	**$27.64**

Table A1-1d. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2022						
Non-Low Production Well Sites	**55,334**	**46,394**	**30,378**	**8,445**	**$47.51**	**$41.60**
Gas Well Sites	8,492	5,965	7,053	1,961	$6.11	$4.74
Oil Well Sites (GOR > 300)	39,001	34,029	20,693	5,752	$34.85	$30.82
Oil Well Sites (GOR < 300)	7,841	6,400	2,632	732	$6.55	$6.04
Low Production Well Sites	**16,132**	**11,776**	**5,671**	**1,576**	**$12.06**	**$10.96**
Gas Well Sites	1,734	1,347	1,294	360	$1.38	$1.13
Oil Well Sites (GOR > 300)	5,186	3,503	1,844	512	$3.59	$3.23
Oil Well Sites (GOR < 300)	9,212	6,926	2,533	704	$7.09	$6.60
Well Sites Total	**71,466**	**58,170**	**36,049**	**10,021**	**$59.57**	**$52.55**
Gathering & Boosting	1,696	1,696	23,841	6,627	$31.41	$26.76
Transmission	288	288	4,653	129	$5.26	$4.45
Storage	16	16	912	25	$0.49	$0.33
Compressor Stations Total	**2,000**	**2,000**	**29,406**	**6,781**	**$37.15**	**$31.54**

Table A1-1e. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2023						
Non-Low Production Well Sites	**63,334**	**53,101**	**34,771**	**9,665**	**$54.38**	**$47.37**
Gas Well Sites	9,720	6,827	8,073	2,244	$6.99	$5.36
Oil Well Sites (GOR > 300)	44,639	38,949	23,685	6,584	$39.89	$35.11
Oil Well Sites (GOR < 300)	8,975	7,325	3,013	837	$7.50	$6.89
Low Production Well Sites	**18,464**	**13,480**	**6,490**	**1,805**	**$13.80**	**$12.50**
Gas Well Sites	1,984	1,542	1,481	412	$1.58	$1.28
Oil Well Sites (GOR > 300)	5,936	4,010	2,110	587	$4.11	$3.68
Oil Well Sites (GOR < 300)	10,544	7,928	2,899	806	$8.12	$7.53
Well Sites Total	**81,798**	**66,581**	**41,261**	**11,470**	**$68.18**	**$59.86**
Gathering & Boosting	1,908	1,908	26,821	7,456	$35.33	$29.92
Transmission	324	324	5,235	145	$5.92	$4.97
Storage	18	18	1,026	28	$0.55	$0.36
Compressor Stations Total	**2,250**	**2,250**	**33,082**	**7,629**	**$41.80**	**$35.26**

Table A1-1f. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2024						
Non-Low Production Well Sites	**71,459**	**59,913**	**39,231**	**10,905**	**$61.36**	**$53.22**
Gas Well Sites	10,967	7,703	9,109	2,532	$7.89	$6.00
Oil Well Sites (GOR > 300)	50,366	43,945	26,723	7,428	$45.00	$39.46
Oil Well Sites (GOR < 300)	10,126	8,265	3,399	945	$8.46	$7.76
Low Production Well Sites	**20,833**	**15,209**	**7,324**	**2,036**	**$15.58**	**$14.06**
Gas Well Sites	2,239	1,740	1,672	465	$1.78	$1.44
Oil Well Sites (GOR > 300)	6,698	4,524	2,381	662	$4.63	$4.14
Oil Well Sites (GOR < 300)	11,896	8,945	3,271	909	$9.16	$8.48
Well Sites Total	**92,292**	**75,122**	**46,555**	**12,941**	**$76.93**	**$67.27**
Gathering & Boosting	2,120	2,120	29,801	8,284	$39.26	$33.07
Transmission	360	360	5,816	161	$6.58	$5.50
Storage	20	20	1,140	32	$0.61	$0.40
Compressor Stations Total	**2,500**	**2,500**	**36,757**	**8,477**	**$46.44**	**$38.97**

Table A1-1g. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2025						
Non-Low Production Well Sites	**79,616**	**66,752**	**43,708**	**12,150**	**$68.36**	**$58.99**
Gas Well Sites	12,219	8,583	10,148	2,821	$8.79	$6.61
Oil Well Sites (GOR > 300)	56,115	48,961	29,773	8,276	$50.14	$43.76
Oil Well Sites (GOR < 300)	11,282	9,208	3,787	1,053	$9.43	$8.62
Low Production Well Sites	**23,210**	**16,946**	**8,158**	**2,268**	**$17.35**	**$15.60**
Gas Well Sites	2,494	1,939	1,862	518	$1.99	$1.59
Oil Well Sites (GOR > 300)	7,462	5,041	2,652	737	$5.16	$4.59
Oil Well Sites (GOR < 300)	13,254	9,966	3,644	1,013	$10.21	$9.42
Well Sites Total	**102,826**	**83,698**	**51,866**	**14,418**	**$85.71**	**$74.59**
Gathering & Boosting	2,332	2,332	32,781	9,112	$43.18	$36.15
Transmission	396	396	6,398	177	$7.23	$6.01
Storage	22	22	1,253	35	$0.67	$0.43
Compressor Stations Total	**2,750**	**2,750**	**40,432**	**9,324**	**$51.08**	**$42.59**

Table A1-2a. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2019						
Non-Low Production Well Sites	**32,720**	**27,433**	**13,472**	**3,745**	**$21.07**	**$18.66**
Gas Well Sites	5,022	3,527	3,128	870	$2.71	$2.15
Oil Well Sites (GOR > 300)	23,062	20,122	9,177	2,551	$15.45	$13.81
Oil Well Sites (GOR < 300)	4,636	3,784	1,167	324	$2.91	$2.70
Low Production Well Sites	**9,539**	**6,965**	**2,515**	**699**	**$5.35**	**$4.90**
Gas Well Sites	1,025	797	574	160	$0.61	$0.51
Oil Well Sites (GOR > 300)	3,067	2,072	818	227	$1.59	$1.44
Oil Well Sites (GOR < 300)	5,447	4,096	1,123	312	$3.15	$2.94
Well Sites Total	**42,259**	**34,398**	**15,987**	**4,444**	**$26.42**	**$23.56**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-2b. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2020						
Non-Low Production Well Sites	**39,993**	**33,531**	**16,467**	**4,578**	**$25.75**	**$22.55**
Gas Well Sites	6,138	4,311	3,823	1,063	$3.31	$2.57
Oil Well Sites (GOR > 300)	28,188	24,594	11,217	3,118	$18.89	$16.71
Oil Well Sites (GOR < 300)	5,667	4,626	1,427	397	$3.55	$3.27
Low Production Well Sites	**11,659**	**8,512**	**3,074**	**855**	**$6.54**	**$5.94**
Gas Well Sites	1,253	974	702	195	$0.75	$0.61
Oil Well Sites (GOR > 300)	3,748	2,532	999	278	$1.94	$1.75
Oil Well Sites (GOR < 300)	6,658	5,006	1,373	382	$3.84	$3.58
Well Sites Total	**51,652**	**42,043**	**19,541**	**5,433**	**$32.29**	**$28.49**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-2c. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2021						
Non-Low Production Well Sites	**47,537**	**39,857**	**19,574**	**5,440**	**$30.61**	**$26.83**
Gas Well Sites	7,296	5,125	4,545	1,263	$3.94	$3.06
Oil Well Sites (GOR > 300)	33,505	29,234	13,333	3,706	$22.45	$19.88
Oil Well Sites (GOR < 300)	6,736	5,498	1,696	471	$4.22	$3.90
Low Production Well Sites	**13,858**	**10,118**	**3,654**	**1,016**	**$7.77**	**$7.07**
Gas Well Sites	1,489	1,158	834	232	$0.89	$0.73
Oil Well Sites (GOR > 300)	4,455	3,010	1,188	330	$2.31	$2.08
Oil Well Sites (GOR < 300)	7,914	5,950	1,632	454	$4.57	$4.26
Well Sites Total	**61,395**	**49,975**	**23,228**	**6,456**	**$38.38**	**$33.90**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-2d. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2022						
Non-Low Production Well Sites	**55,334**	**46,394**	**22,784**	**6,333**	**$35.63**	**$31.20**
Gas Well Sites	8,492	5,965	5,290	1,470	$4.58	$3.55
Oil Well Sites (GOR > 300)	39,001	34,029	15,520	4,314	$26.14	$23.11
Oil Well Sites (GOR < 300)	7,841	6,400	1,974	549	$4.92	$4.53
Low Production Well Sites	**16,132**	**11,776**	**4,253**	**1,182**	**$9.05**	**$8.22**
Gas Well Sites	1,734	1,347	971	270	$1.03	$0.85
Oil Well Sites (GOR > 300)	5,186	3,503	1,383	384	$2.69	$2.42
Oil Well Sites (GOR < 300)	9,212	6,926	1,899	528	$5.32	$4.95
Well Sites Total	**71,466**	**58,170**	**27,037**	**7,515**	**$44.68**	**$39.41**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-2e. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2023						
Non-Low Production Well Sites	**63,334**	**53,101**	**26,079**	**7,249**	**$40.78**	**$35.53**
Gas Well Sites	9,720	6,827	6,055	1,683	$5.24	$4.02
Oil Well Sites (GOR >300)	44,639	38,949	17,764	4,938	$29.91	$26.33
Oil Well Sites (GOR < 300)	8,975	7,325	2,260	628	$5.63	$5.17
Low Production Well Sites	**18,464**	**13,480**	**4,868**	**1,353**	**$10.35**	**$9.37**
Gas Well Sites	1,984	1,542	1,111	309	$1.18	$0.96
Oil Well Sites (GOR > 300)	5,936	4,010	1,583	440	$3.08	$2.76
Oil Well Sites (GOR < 300)	10,544	7,928	2,174	604	$6.09	$5.65
Well Sites Total	**81,798**	**66,581**	**30,947**	**8,602**	**$51.14**	**$44.90**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-2f. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2024						
Non-Low Production Well Sites	**71,459**	**59,913**	**29,422**	**8,179**	**$46.02**	**$39.91**
Gas Well Sites	10,967	7,703	6,831	1,899	$5.92	$4.50
Oil Well Sites (GOR > 300)	50,366	43,945	20,042	5,571	$33.75	$29.59
Oil Well Sites (GOR <300)	10,126	8,265	2,549	709	$6.35	$5.82
Low Production Well Sites	**20,833**	**15,209**	**5,493**	**1,526**	**$11.68**	**$10.54**
Gas Well Sites	2,239	1,740	1,254	348	$1.34	$1.08
Oil Well Sites (GOR > 300)	6,698	4,524	1,786	496	$3.47	$3.10
Oil Well Sites (GOR < 300)	11,896	8,945	2,453	682	$6.87	$6.36
Well Sites Total	**92,292**	**75,122**	**34,915**	**9,705**	**$57.70**	**$50.45**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-2g. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2025						
Non-Low Production Well Sites	**79,616**	**66,752**	**32,781**	**9,113**	**$51.27**	**$44.24**
Gas Well Sites	12,219	8,583	7,611	2,116	$6.59	$4.96
Oil Well Sites (GOR >300)	56,115	48,961	22,330	6,207	$37.60	$32.82
Oil Well Sites (GOR < 300)	11,282	9,208	2,840	790	$7.07	$6.46
Low Production Well Sites	**23,210**	**16,946**	**6,119**	**1,701**	**$13.01**	**$11.70**
Gas Well Sites	2,494	1,939	1,397	388	$1.49	$1.19
Oil Well Sites (GOR > 300)	7,462	5,041	1,989	553	$3.87	$3.45
Oil Well Sites (GOR < 300)	13,254	9,966	2,733	760	$7.65	$7.07
Well Sites Total	**102,826**	**83,698**	**38,900**	**10,814**	**$64.28**	**$55.94**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-3a. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2019						
Non-Low Production Well Sites	**32,720**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	5,022	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	23,062	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	4,636	0	0	0	$0.00	$0.00
Low Production Well Sites	**9,539**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	1,025	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	3,067	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	5,447	0	0	0	$0.00	$0.00
Well Sites Total	**42,259**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,060	1,060	7,450	2,071	$13.09	$11.75
Transmission	180	180	1,454	40	$2.19	$1.96
Storage	10	10	285	8	$0.20	$0.16
Compressor Stations Total	**1,250**	**1,250**	**9,189**	**2,119**	**$15.48**	**$13.87**

Table A1-3b. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2020						
Non-Low Production Well Sites	**39,993**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	6,138	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	28,188	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	5,667	0	0	0	$0.00	$0.00
Low Production Well Sites	**11,659**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	1,253	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	3,748	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	6,658	0	0	0	$0.00	$0.00
Well Sites Total	**51,652**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,272	1,272	8,940	2,485	$15.70	$13.96
Transmission	216	216	1,745	48	$2.63	$2.33
Storage	12	12	342	9	$0.24	$0.18
Compressor Stations Total	**1,500**	**1,500**	**11,027**	**2,542**	**$18.58**	**$16.47**

Table A1-3c. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2021						
Non-Low Production Well Sites	**47,537**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	7,296	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	33,505	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	6,736	0	0	0	$0.00	$0.00
Low Production Well Sites	**13,858**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	1,489	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	4,455	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	7,914	0	0	0	$0.00	$0.00
Well Sites Total	**61,395**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,484	1,484	10,430	2,899	$18.32	$16.31
Transmission	252	252	2,036	56	$3.07	$2.72
Storage	14	14	399	11	$0.28	$0.21
Compressor Stations Total	**1,750**	**1,750**	**12,865**	**2,966**	**$21.67**	**$19.24**

Table A1-3d. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2022						
Non-Low Production Well Sites	**55,334**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	8,492	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	39,001	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	7,841	0	0	0	$0.00	$0.00
Low Production Well Sites	**16,132**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	1,734	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	5,186	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	9,212	0	0	0	$0.00	$0.00
Well Sites Total	**71,466**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,696	1,696	11,920	3,314	$20.94	$18.62
Transmission	288	288	2,327	64	$3.51	$3.10
Storage	16	16	456	13	$0.32	$0.24
Compressor Stations Total	**2,000**	**2,000**	**14,703**	**3,391**	**$24.77**	**$21.96**

Table A1-3e. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2023						
Non-Low Production Well Sites	**63,334**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	9,720	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	44,639	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	8,975	0	0	0	$0.00	$0.00
Low Production Well Sites	**18,464**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	1,984	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	5,936	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	10,544	0	0	0	$0.00	$0.00
Well Sites Total	**81,798**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,908	1,908	13,410	3,728	$23.55	$20.85
Transmission	324	324	2,617	73	$3.95	$3.47
Storage	18	18	513	14	$0.36	$0.27
Compressor Stations Total	**2,250**	**2,250**	**16,540**	**3,815**	**$27.86**	**$24.60**

Table A1-3f. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2024						
Non-Low Production Well Sites	**71,459**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	10,967	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	50,366	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	10,126	0	0	0	$0.00	$0.00
Low Production Well Sites	**20,833**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	2,239	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	6,698	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	11,896	0	0	0	$0.00	$0.00
Well Sites Total	**92,292**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	2,120	2,120	14,900	4,142	$26.17	$23.08
Transmission	360	360	2,908	81	$4.38	$3.84
Storage	20	20	570	16	$0.41	$0.30
Compressor Stations Total	**2,500**	**2,500**	**18,378**	**4,239**	**$30.96**	**$27.22**

Table A1-3g. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2025						
Non-Low Production Well Sites	**79,616**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	12,219	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	56,115	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	11,282	0	0	0	$0.00	$0.00
Low Production Well Sites	**23,210**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	2,494	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	7,462	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	13,254	0	0	0	$0.00	$0.00
Well Sites Total	**102,826**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	2,332	2,332	16,390	4,556	$28.79	$25.27
Transmission	396	396	3,199	89	$4.82	$4.21
Storage	22	22	627	17	$0.45	$0.33
Compressor Stations Total	**2,750**	**2,750**	**20,216**	**4,662**	**$34.06**	**$29.81**

Table A1-4a. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2019						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Well Sites Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,060	0	0	0	$0.00	$0.00
Transmission	180	0	0	0	$0.00	$0.00
Storage	10	0	0	0	$0.00	$0.00
Compressor Stations Total	**1,250**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-4b. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2020						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Well Sites Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,272	0	0	0	$0.00	$0.00
Transmission	216	0	0	0	$0.00	$0.00
Storage	12	0	0	0	$0.00	$0.00
Compressor Stations Total	**1,500**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-4c. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2021						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Well Sites Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,484	0	0	0	$0.00	$0.00
Transmission	252	0	0	0	$0.00	$0.00
Storage	14	0	0	0	$0.00	$0.00
Compressor Stations Total	**1,750**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-4d. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2022						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Well Sites Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,696	0	0	0	$0.00	$0.00
Transmission	288	0	0	0	$0.00	$0.00
Storage	16	0	0	0	$0.00	$0.00
Compressor Stations Total	**2,000**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-4e. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2023						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Well Sites Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,908	0	0	0	$0.00	$0.00
Transmission	324	0	0	0	$0.00	$0.00
Storage	18	0	0	0	$0.00	$0.00
Compressor Stations Total	**2,250**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-4f. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2024						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Well Sites Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	2,120	0	0	0	$0.00	$0.00
Transmission	360	0	0	0	$0.00	$0.00
Storage	20	0	0	0	$0.00	$0.00
Compressor Stations Total	**2,500**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-4g. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2025						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Well Sites Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	2,332	0	0	0	$0.00	$0.00
Transmission	396	0	0	0	$0.00	$0.00
Storage	22	0	0	0	$0.00	$0.00
Compressor Stations Total	**2,750**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-5a. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2019						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**9,539**	**6,970**	**5,030**	**1,398**	**$10.70**	**$9.80**
Gas Well Sites	1,025	797	1,148	319	$1.22	$1.02
Oil Well Sites (GOR > 300)	3,067	2,077	1,636	455	$3.18	$2.89
Oil Well Sites (GOR < 300)	5,447	4,096	2,246	624	$6.29	$5.89
Well Sites Total	**9,539**	**6,970**	**5,030**	**1,398**	**$10.70**	**$9.80**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-5b. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2020						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**11,659**	**8,518**	**6,149**	**1,709**	**$13.08**	**$11.88**
Gas Well Sites	1,253	974	1,403	390	$1.50	$1.22
Oil Well Sites (GOR > 300)	3,748	2,538	2,000	556	$3.89	$3.50
Oil Well Sites (GOR < 300)	6,658	5,006	2,746	763	$7.69	$7.16
Well Sites Total	**11,659**	**8,518**	**6,149**	**1,709**	**$13.08**	**$11.88**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-5c. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2021						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**13,858**	**10,125**	**7,310**	**2,032**	**$15.55**	**$14.14**
Gas Well Sites	1,489	1,158	1,668	464	$1.78	$1.46
Oil Well Sites (GOR > 300)	4,455	3,017	2,378	661	$4.63	$4.17
Oil Well Sites (GOR < 300)	7,914	5,950	3,264	907	$9.14	$8.51
Well Sites Total	**13,858**	**10,125**	**7,310**	**2,032**	**$15.55**	**$14.14**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-5d. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2022						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**16,132**	**11,785**	**8,509**	**2,365**	**$18.10**	**$16.44**
Gas Well Sites	1,734	1,347	1,942	540	$2.07	$1.69
Oil Well Sites (GOR > 300)	5,186	3,512	2,768	769	$5.39	$4.85
Oil Well Sites (GOR < 300)	9,212	6,926	3,799	1,056	$10.64	$9.90
Well Sites Total	**16,132**	**11,785**	**8,509**	**2,365**	**$18.10**	**$16.44**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-5e. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2023						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**18,464**	**13,490**	**9,738**	**2,708**	**$20.71**	**$18.75**
Gas Well Sites	1,984	1,542	2,222	618	$2.37	$1.92
Oil Well Sites (GOR > 300)	5,936	4,020	3,168	881	$6.16	$5.53
Oil Well Sites (GOR < 300)	10,544	7,928	4,348	1,209	$12.18	$11.30
Well Sites Total	**18,464**	**13,490**	**9,738**	**2,708**	**$20.71**	**$18.75**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-5f. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2024						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**20,833**	**15,220**	**10,987**	**3,054**	**$23.37**	**$21.09**
Gas Well Sites	2,239	1,740	2,507	697	$2.67	$2.15
Oil Well Sites (GOR > 300)	6,698	4,535	3,574	993	$6.96	$6.21
Oil Well Sites (GOR < 300)	11,896	8,945	4,906	1,364	$13.74	$12.72
Well Sites Total	**20,833**	**15,220**	**10,987**	**3,054**	**$23.37**	**$21.09**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-5g. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2025						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**23,210**	**16,958**	**12,242**	**3,403**	**$26.04**	**$23.41**
Gas Well Sites	2,494	1,939	2,794	777	$2.98	$2.38
Oil Well Sites (GOR > 300)	7,462	5,053	3,982	1,107	$7.75	$6.90
Oil Well Sites (GOR < 300)	13,254	9,966	5,466	1,519	$15.31	$14.14
Well Sites Total	**23,210**	**16,958**	**12,242**	**3,403**	**$26.04**	**$23.41**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Attachment 2

Supporting Information for Certifications

Table A2-1a. Estimated Count of Affected Facilities Requiring Certifications for 2019

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	9,597
Total	13,417

Table A2-1b. Estimated Count of Affected Facilities Requiring Certifications for 2020

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	10,375
Total	14,195

Table A2-1c. Estimated Count of Affected Facilities Requiring Certifications for 2021

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	10,762
Total	14,582

Table A2-1d. Estimated Count of Affected Facilities Requiring Certifications for 2022

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	11,123
Total	14,943

Table A2-1e. Estimated Count of Affected Facilities Requiring Certifications for 2023

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	10,413
Total	15,233

Table A2-1f. Estimated Count of Affected Facilities Requiring Certifications for 2024

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	11,591
Total	15,411

Table A2-1g. Estimated Count of Affected Facilities Requiring Certifications for 2025

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	11,026
Total	15,456

Table A2-2a. Summary of National Level Impact for PE Certification Alternatives in 2019

Certification Costs - 2019	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	13,417	$7,334,666
Cost Estimate for Proposed Reconsideration	13,417	$4,804,578
Reduced Burden of Proposed In-House Engineer Certification	13,417	$2,530,088

Table A2-2b. Summary of National Level Impact for PE Certification Alternatives in 2020

Certification Costs - 2020	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	14,195	$7,759,589
Cost Estimate for Proposed Reconsideration	14,195	$5,082,924
Reduced Burden of Proposed In-House Engineer Certification	14,195	$2,676,665

Table A2-2c. Summary of National Level Impact for PE Certification Alternatives in 2021

Certification Costs - 2021	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	14,582	$7,971,475
Cost Estimate for Proposed Reconsideration	14,582	$5,221,720
Reduced Burden of Proposed In-House Engineer Certification	14,582	$2,749,755

Table A2-2d. Summary of National Level Impact for PE Certification Alternatives in 2022

Certification Costs - 2022	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	14,943	$8,168,556
Cost Estimate for Proposed Reconsideration	14,943	$5,350,818
Reduced Burden of Proposed In-House Engineer Certification	14,943	$2,817,738

Table A2-2e. Summary of National Level Impact for PE Certification Alternatives in 2023

Certification Costs - 2023	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	15,233	$8,327,068
Cost Estimate for Proposed Reconsideration	15,233	$5,454,652
Reduced Burden of Proposed In-House Engineer Certification	15,233	$2,872,417

Table A2-2f. Summary of National Level Impact for PE Certification Alternatives in 2024

Certification Costs - 2024	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	15,411	$8,424,421
Cost Estimate for Proposed Reconsideration	15,411	$5,518,422
Reduced Burden of Proposed In-House Engineer Certification	15,411	$2,905,998

Table A2-2g. Summary of National Level Impact for PE Certification Alternatives in 2025

Certification Costs - 2025	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	15,456	$8,449,280
Cost Estimate for Proposed Reconsideration	15,456	$5,534,706
Reduced Burden of Proposed In-House Engineer Certification	15,456	$2,914,573

EPA United States Environmental Protection Agency

EO12866_Oil and Gas Reconsideration Proposal 2060-AT54 TSD ~~20180607~~20180621

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

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Proposed Reconsideration of the New Source Performance Standards
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ACRONYMS AND ABBREVIATIONS

Acronyms/Abbreviations	Description
AEO	Annual Energy Outlook
bbl	barrel
boe	Barrels of oil equivalent
BSER	best system of emission reduction
EPA	Environmental Protection Agency
GHG	greenhouse gas
GOR	gas to oil ratio
LDAR	leak detection and repair
Mcf	thousand cubic feet
NSPS	New Source Performance Standards
OEL	open-ended line
OGI	optical gas imaging
PE	professional engineer
PRV	pressure relief valve
scf	standard cubic feet
SOCMI	Synthetic Organic Chemical Manufacturing Industry
tpy	tons per year
TOC	total organic compounds
TSD	Technical Support Document
VOC	volatile organic compounds
VRU	Vapor recovery unit

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1.0 INTRODUCTION

This background technical support document (TSD) provides information relevant to the proposed reconsideration of the Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources ("2016 NSPS OOOOa"). This TSD is presented in two volumes; Volume 1 provides the unit-level analysis supporting the determination of the best system of emission reduction (BSER); and Volume 2 presents the national impacts of the regulatory decisions for the proposed reconsideration.

1.1 Volume 1 - Unit-Level BSER Analysis

The proposed reconsideration only proposes updates to the BSER analysis for fugitive emissions requirements at well sites and compressor stations. Chapter 2 presents detailed information and analyses pertaining to these proposed requirements, including emission data and discussions of available control options and their costs that were considered in the development of standards reflecting the BSER for these emission sources.

1.2 Volume 2 - National Level Impacts

Chapters 3 and 4 present the estimates of national level impacts needed to inform the preamble of the proposed rule and the Regulatory Impact Analysis (RIA) for this proposal, as required under Executive Order 12866. In this volume, we focus on the proposed amendments that result in a change in cost or emissions compared to an updated baseline. The relevant provisions include the fugitive emission requirements and professional engineer certifications for pneumatic pumps and closed vent systems.

It is important to note that national impacts estimates incorporate in to the baseline the fact that some states already have requirements of emissions sources addressed by this proposed rule. Further, this analysis is separate and apart from the analysis required to identify the BSER, which establishes the requirements under section 111(b) of the Clean Air Act (CAA).

1.3 Supporting Documentation

This action follows the development of several prior oil and gas NSPS related actions. This review references several documents that were published as a consequence of these prior actions. For ease of presentation, the following documents are consistently cited in the following sections:

- The gas composition memo that was developed during the NSPS process which characterizes and analyzes data to determine the gas composition and develop ratios for natural gas composition to be used for the various segments in the development of regulations for the oil and natural gas

sector. This document will be referred to as "2011 Gas Composition Memorandum".[1]

- Emissions information and equipment counts for various emission sources were developed from data used to calculate national emissions in the Inventory of U.S. Greenhouse Gas Emissions and Sinks, which incorporates facility-level data submitted to the Greenhouse Gas Reporting Program (GHGRP).[2,3] The most recent available data from the GHG Inventory at the time of the development of this analysis was for 2016, and was used for various portions of the analysis. For the purposes of this document these data sources are referred to as "GHG Inventory" and "GHGRP". The most recent available GHG Inventory covers data from 1990-2016 and currently available GHGRP data cover 2011-2016. These new emissions and activity data have been reviewed for the proposed reconsideration and incorporated into this analysis.
- The TSD for the 2015 NSPS proposal, published in August, 2015, will be referred to in this document as "2015 NSPS Proposal TSD".[4]
- The TSD for the 2016 final NSPS standards, published in May, 2016, will be referred to in this document as "2016 NSPS Final TSD".[5]

All of the calculations supporting the analyses in this document are included in the docket in the form of spreadsheets that are labeled corresponding to the section of this TSD.

[1] Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. "Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking". July 2011. Docket ID No. EPA-HQ-OAR-2010-0505-0084.
[2] EPA 2018. Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2016. Available at: https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks.
[3] EPA 2017. Greenhouse Gas Reporting Program. Data reported as of August 5, 2017. Available at: https://www.epa.gov/ghgreporting.
[4] Docket ID No. EPA-HQ-OAR-2010-0505-5021
[5] Docket ID No. EPA-HQ-OAR-2010-0505-7631

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VOLUME 1: UNIT LEVEL BSER ANALYSIS

2.0 FUGITIVE EMISSIONS STANDARDS

Fugitive emissions from components located at well sites and compressor stations are a source of methane and volatile organic compound (VOC) emissions. This chapter explains the causes for these fugitive emissions, provides estimates of methane and VOC emissions for "model" facilities, and provides estimates of nationwide fugitive emissions for new sources in the production, transmission, and storage segments of the crude oil and natural gas source category. Programs that are designed to reduce fugitive emissions are explained in this chapter, as well as estimated costs, estimated emission reductions, and secondary impacts. Finally, this chapter discusses considerations in developing regulatory alternatives for fugitive emissions from major production and processing equipment located at well sites and equipment located at compressor stations.

2.1 Fugitive Emissions Description

There are several potential sources of fugitive emissions throughout the oil and natural gas source category. Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Changes in pressure and mechanical stresses can also cause components or equipment to emit fugitive emissions. Poor maintenance or operating practices, such as improperly reseated pressure relief valves (PRVs) or worn gaskets on thief hatches on controlled storage vessels are also potential causes of fugitive emissions. Additional sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices such as PRVs, pump seals, valves or controlled liquid storage tanks. These fugitive emissions do not include devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pneumatic pumps, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission.

As discussed in section 2.2, the 2016 NSPS OOOOa promulgated fugitive emissions standards for well sites and compressor stations in addition to the previously promulgated equipment leak standards for onshore natural gas processing plants.[6] In order to differentiate which components and equipment were subject to these standards, the EPA included a separate definition for "fugitive

[6] The Oil and Natural Gas Sector NSPS (40 CFR part 60, subpart OOOO) specifically defines "equipment" relative to standards for equipment leaks of VOC from onshore natural gas processing plants. As used in this chapter, the term "equipment" is used in a broader context and is not meant to be limited by the manner in which the term is currently used in subpart OOOO.

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emissions component". Specifically, the 2016 NSPS OOOOa defined fugitive emissions component as follows:

> *Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station, including but not limited to valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §60.5411a, thief hatches or other openings on a controlled storage vessel not subject to §60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.*

The EPA received feedback through petitions for reconsideration and discussions with various stakeholders that additional changes to the definition may be applicable. One petitioner asserted that the "including but not limited to" description adds uncertainty to what should be included in the collection of fugitive emissions components. Additionally, one petitioner asserted that "compressors" should not be included in the list of fugitive emissions components because they are subject to separate standards as affected facilities within other sections of the 2016 NSPS OOOOa. The EPA is proposing to revise the definition of fugitive emissions component in this reconsideration to remove the terms "including but not limited to" because we recognized the uncertainty when we finalized the 2016 NSPS OOOOa, but is not removing the term compressor from the list of fugitive emissions components. While centrifugal and reciprocating compressors are affected facilities subject to standards, the potential for fugitive emissions remains for compressors. Additionally, the requirements found in 40 CFR 60.5380a or 60.5385a for centrifugal or reciprocating compressors, respectively, are not applicable to compressors located at a well site.

2.2 Fugitive Emissions Requirements in 2016 NSPS OOOOa

On June 3, 2016, the EPA promulgated fugitive emissions standards for well sites and compressor stations at 40 CFR part 60, subpart OOOOa (2016 NSPS OOOOa). These standards required a fugitive emissions monitoring and repair program, where well sites and compressor stations must be monitored semiannually and quarterly, respectively. New, reconstructed, or modified well sites and compressor stations are required to perform an initial monitoring survey within 60 days of the startup of

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production (for well sites) or startup of the compressor station. Owners and operators are required to perform monitoring using optical gas imaging (OGI), where any visible image is defined as a fugitive emission and must be repaired within 30 days of detection and resurveyed within 30 days of repair in order to verify successful repair. As an alternative, Method 21 of Appendix A-7 to Part 60 ("Method 21") may be used to identify fugitive emissions, where an instrument reading of 500 parts per million (ppm) or greater is considered a fugitive emission. Each owner or operator is required to develop and implement a fugitive emissions monitoring plan that includes site-specific information, such as a site map and observation path taken to ensure line of sight for each fugitive emissions component during the monitoring survey, in addition to specifying how the survey will be conducted (*i.e.,* which monitoring instrument will be used, how operator-specified parameters such as viewing distance will be established, and other parameters as defined in the 2016 NSPS OOOOa).

In March 2018, the EPA amended the fugitive emissions standards by removing the requirement that repairs which have been delayed beyond the 30-day deadline are completed during the next unplanned or emergency shutdown or vent blowdown and by establishing separate monitoring requirements for well sites located on the Alaskan North Slope. These amended standards for well sites located on the Alaskan North Slope specify that new well sites that startup production between September and March must conduct initial monitoring within 6 months of the startup of production[7] or by June 30, whichever is later, while well sites that startup production between April and August must comply with the 60-day initial monitoring requirement in the 2016 NSPS OOOOa. Similarly, well sites that are modified between September and March must conduct initial monitoring within 6 months of the first day of production for each collection of fugitive emissions components or by June 30, whichever is later. Further, all well sites located on the Alaskan North Slope that are subject to the fugitive emissions requirements must conduct annual monitoring, instead of the semiannual monitoring required for other well sites. Subsequent annual monitoring must be conducted at least 9 months apart.

2.3 Fugitive Emissions Data and Emissions Factors

2.3.1 Model Plants

The number and type of fugitive emissions components located at well sites and compressor stations can consist of a large variety of combinations of process equipment and other components. This is particularly true for well sites where oil and natural gas production practices and equipment vary from

[7] Startup of production is defined in 40 CFR 60.5430a.

site-to-site. Some production sites may include only a single wellhead that is extracting oil or natural gas from the ground, while other sites may include multiple wellheads attached to a well pad. A well site is a site where the production, extraction, recovery, lifting, stabilization, separation and/or treating of petroleum and/or natural gas (including condensate) occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components that may be sources of fugitive emissions. A well site can serve one well on a pad or multiple wells on a pad. Therefore, the number of components with potential for fugitive emissions can vary depending on the number of wells and the number of major production and processing equipment at the site. Model plants were developed to analyze potential options for the control of fugitive emissions at well sites and compressor stations.

Information related to the fugitive emissions component counts was obtained from the GRI/EPA natural gas industry study,[8] the EPA's Inventory of U.S. Greenhouse Gas Emissions and Sinks for 2016, and the EPA's GHG Mandatory Reporting Rule (40 CFR part 98, subpart W). The GRI/EPA document provided average fugitive emissions component counts for the natural gas production, natural gas processing, natural gas transmission, and natural gas storage sectors, including counts for valves, connectors, OELs, and PRVs. Although these counts do not include all potential fugitive emissions components, as described in the definition of "fugitive emissions component," these remain the best available data.

In the 2016 NSPS Final TSD, we developed three subtypes of well site model plants: (1) gas well site, (2) oil well site with a gas to oil ratio (GOR) of less than 300 scf of gas per stock tank barrel ("GOR<300"), and (3) oil well site with GOR greater than 300 scf of gas per stock tank barrel ("GOR > 300"). However, because additional data regarding low production well sites (*i.e.,* well sites where the average combined oil and natural gas production is less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) is now available, we have subcategorized well sites by production for this proposed reconsideration. Thus, we have developed the following model plant well sites for (1) non-low production sites and (2) low production sites: (a) gas well site, (b) oil well site with GOR <300, and (c) oil well site with GOR >300. In the 2016 NSPS Final TSD, we also developed three subtypes of compressor station model plants: (1) gathering and boosting stations, (2) transmission stations, and (3) storage stations. The following sections discuss the revisions to the non-low production

[8] Gas Research Institute (GRI)/U.S. EPA. *Research and Development, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks*. June 1996 (EPA-600/R-96-080h).

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model plants, development of the low production model plants, and revisions to the compressor station model plants.

2.3.2 Non-low Production Well Site Model Plant Development

For each non-low production well site model plant, we estimated the average number of wells associated with a well site using data from the DrillingInfo HPDI® database.[9] The national average of wells per well site was 1.81, which was rounded to 2.0 wells per well site for each non-low production model plant. The reported equipment counts for each non-low production well site subtype in the GHG Inventory were used to determine the average major production and processing equipment counts per well. These average equipment counts per well were multiplied by the average number of wells at a well site (2) and then rounded up to the nearest integer, consistent with the analysis in the 2016 NSPS Final TSD. The specific types of major production and processing equipment included in the non-low production model well sites include: wellheads, separators, meters/piping, in-line heaters, dehydrators, and storage vessels. The types of fugitive emissions components associated with these production equipment types include: valves, connectors, OELs, PRVs, and thief hatches. Except for storage vessel thief hatches, component counts for each type of production equipment were calculated using the average component counts for onshore production equipment in the Eastern U.S and the Western U.S. from the EPA/GRI report. Fractions of components were rounded up to the nearest integer. It was assumed that each well site has at least 1 storage vessel subject to fugitive emissions requirements, and that each storage vessel contains 1 thief hatch.

Fugitive emissions from storage vessels were not previously considered in the well site model plants because only a limited universe of storage vessels would be subject to the fugitive emissions requirements. Specifically, storage vessels that have the potential to emit 6 tons per year (tpy) or more of VOC are considered affected facilities and subject to the control requirements for storage vessels in 40 CFR 60.5395a. In calculating the potential emissions, owners and operators can take into account emission limits in practically and legally enforceable permits. Therefore, there can be a universe of controlled storage vessels that are not subject to the control requirements in the 2016 NSPS OOOOa for affected facility storage vessels. These controlled storage vessels are then subject to the fugitive emissions requirements if they are located at a well site or compressor station that is subject to the fugitive emissions requirements. In evaluating appropriate monitoring frequencies for fugitive emissions components, the EPA considered data indicating that leak rates from storage vessels may be much

[9] Drilling Information, Inc. 2014. *DI Desktop.* 2014 Production Information Database.

higher than those for other fugitive components and that many operators may be claiming many of their storage vessels as being subject to the fugitives monitoring program rather than affected facilities subject to the 2016 NSPS OOOOa control requirements for storage vessels found in 40 CFR 60.5395a.

The EPA has observed extensive leak rates from storage vessels at oil and natural gas production well pads through inspection efforts in many locations, including Colorado, Ohio, and Texas. As an example, in 2012 inspectors from the EPA and the Colorado Department of Public Health and Environment (CDPHE) observed emissions using OGI from storage vessels in tank batteries receiving production from 119 of 177 wells (or 63 of 99 inspected tank batteries). Potential causes of storage vessel emissions include inadequate design, operation, or maintenance. To address these potential causes, the EPA and CDPHE lodged a settlement with Noble Energy, Inc. (Noble) in April 2015.

Since that time, the EPA has received extensive reports from Noble pursuant to the settlement agreement that provide updates as to settlement implementation. The settlement included a requirement to perform an engineering evaluation to ensure adequate design for each tank battery. The engineering evaluation deadlines were staggered with tank batteries placed into one of five groups, each with a different deadline. The final deadline was July 1, 2017. After each deadline, the EPA receives a "Certification of Completion Report" that lists the tank systems for which Noble has completed its engineering evaluation. The EPA also receives an "End of Phase Report," which includes a list of emissions observed from storage vessels from the date the engineering evaluation was completed for a tank system through the end of that reporting period (typically around 5-11 months). These End of Phase Reports are reviewed by EPA and CDPHE and then posted to Noble's website at noblecolorado.com. Finally, the EPA receives semi-annual reports that list instances of emissions from storage vessels during that six-month reporting period. To better understand storage vessel leak rates, excluding design issues, the EPA looked at these reports to ascertain what portion of tank batteries had one or more storage vessel leaks in the period between completion of the engineering evaluation and the end of the relevant reporting period (End of Phase Reports for tank batteries in Groups I through III and semi-annual reporting period for tank batteries greater than 50 tpy actual uncontrolled emissions or in the cross-section sampling analysis group). A total of 621 tank batteries were certified in those five groups' Certification of Completion Reports. Approximately 40% of those had one or more storage vessel leaks detected with OGI during the 5-26 months of monitoring before the end of the relevant reporting

period.[10] Note that the OGI monitoring frequency required by the Noble settlement ranges from monthly down to no OGI monitoring, depending on the tank battery, so not all tank batteries were necessarily monitored during the period in question but some tank batteries were monitored many times. Based on EPA inspection results in various basins and analysis of Noble's post-design analysis inspection data, the EPA believes that leak rates for storage vessels are much higher than those for other fugitive components at well pads.

Inspection data and compliance reports for the 2016 NSPS OOOOa indicate that many operators determined that few or no storage vessels are affected facilities under the 2016 NSPS OOOOa. For example, review of the 2016 NSPS OOOOa compliance reports indicates that some operators may be incorrectly averaging emissions across storage tanks in tank batteries when determining the potential for VOC emissions. Both the 2012 NSPS OOOO and 2016 NSPS OOOOa specify that a storage vessel affected facility is "a single storage vessel" that "has the potential for VOC emissions equal to or greater than 6 tpy." 40 CFR 60.5365(e) and 60.5365a(e). In prior rulemakings, the EPA explained that storage vessel emission estimation methods for the potential for VOC emissions generally require information on both the composition and volumetric rate of the liquid entering the storage vessel, where the volumetric throughput is frequently calculated by recording the volume of liquid collected from the receiving vessel(s) over time. 79 FR 79026. Because the 2012 NSPS OOOO and 2016 NSPS OOOOa define the affected facility as "a single storage vessel," the determination of the potential for VOC emissions must be based on the liquid throughput of each "single storage vessel," even where the storage vessel is part of a tank battery. Operators should ensure that the determination of the potential for VOC emissions reflects each storage vessel's actual configuration and operational characteristics. Furthermore, if a storage vessel's configuration or operational characteristics are intended to avoid the 2012 NSPS OOOO or 2016 NSPS OOOOa applicability, the NSPS General Provisions on circumvention at 40 CFR 60.12 may provide grounds for state or federal enforcement. Similarly, the EPA notes that affected facility determinations are allowed to account for legally and practically enforceable limits in determining the potential for VOC emissions for a storage vessel. However, 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. Given the potential for recurring emissions from controlled

[10] Memorandum from Virginia Sorrell, EPA to Apple Chapman and Phil Brooks, EPA, *Analysis of Consent Decree Reports from Noble Energy, Inc. as to Emissions Observations from Thief Hatches or Other Openings on Controlled Storage Vessels; Oil and Natural Gas Sector: Emission Standards for New, Reconstructed and Modified Sources Reconsideration – SAN 5719.8* located at Docket ID No. EPA-HQ-OAR-2017-0483.

storage vessel thief hatches or other opening owing to operation and maintenance performance even where adequate design has been verified, any limit on capture and control efficiency from storage vessels must include sufficient monitoring to timely identify and repair emissions from storage vessels to ensure the limit on capture and control efficiency is consistently achieved.

Where a storage vessel is part of a tank battery, some operators appear to derive the maximum daily throughput of a storage vessel in a battery by using the throughput to the entire battery (by using records of liquids collected from the battery over time) and dividing that figure by the number of storage vessels in the battery. This approach for determining a storage vessel's maximum daily throughput is incorrect for certain operational configurations. For instance, where a tank battery is operated such that all pressurized liquids from the separator initially flow to only one storage vessel, and then overflow to the next, and so on (*i.e.,* in series or series flow), the first individual storage vessel's throughput would be the entire battery's throughput, not the entire battery's throughput apportioned evenly among the storage vessels. Dividing an entire battery's throughput by the number of storage vessels in the battery would greatly underestimate flash emissions from the first storage vessel connected in series, which is where liquid pressure drops from separator pressure to atmospheric pressure. However, such division could be appropriate where all liquids flow through a splitter system in a common header that ensures that all liquids initially flow in equal amounts to all storage vessels in a tank battery at all times since the liquid pressure drop would occur equally in each storage vessel in the battery.

In summary, in proposing these revisions to the 2016 NSPS OOOOa, the EPA concluded that the higher potential frequency and magnitude of storage vessel emissions will typically be addressed through the requirements for storage vessel affected facilities rather than through the fugitives monitoring requirements where operators correctly determine potential for VOC emissions for individual storage vessels. Additionally, the EPA notes that affected facility determinations are allowed to account for legally and practically enforceable limits in determining the potential for VOC emissions for a storage vessel. However, 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 terms and conditions such that the source cannot lawfully exceed the limit. Given the potential for recurring emissions from storage vessels owing to operation and maintenance performance even where adequate design has been verified, any limit on capture and control efficiency from storage vessels must include sufficient monitoring to timely identify and repair storage vessel leaks such that the limit on capture and control efficiency is consistently achieved. In such cases, the legally and practically enforceable limit would be providing storage vessel monitoring requirements to address the higher potential frequency and

magnitude of storage vessel emissions and any monitoring through the 2016 NSPS OOOOa fugitives monitoring program would be secondary. In light of the above, it is estimated that 1 controlled storage vessel will be subject to the fugitive emissions requirements at each well site for purposes of development of the revised model plants.

A summary of the fugitive emissions component counts for the non-low production model plants is presented in Table 2-1 for non-low production. Specific changes from the 2016 NSPS OOOOa model plants include the following:

- Reduced the number of meter/piping from 3 to 2 for gas well sites and oil well sites with GOR >300, and
- Added 1 controlled storage vessel thief hatch to each of the non-low production model plants.

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Table 2-1. Average Fugitive Emissions Component Count for Non-Low Production Well Site Model Plants

Production Equipment	Model Plant Equipment Counts	Average Component Count Per Unit of Model Plant[a]				
		Valves	Connectors	OELs	PRVs	Thief Hatches
Non-Low Production Natural Gas Well Site Model Plant						
Wellheads	2	19.0	74.0	2.0	0.0	--
Separators	2	43.0	137.0	8.0	3.0	--
Meters/Piping	2	26.0	96.0	1	1.0	--
In-Line Heaters	1	14.0	65.0	2.0	1.0	--
Dehydrators	1	24.0	90.0	2.0	2.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	127.0	462.0	14.0	7.0	1.0
Non-Low Production Oil Well Site (<300 GOR) Model Plant						
Wellheads	2	10.0	8.0	0.0	2.0	--
Separators	1	6.0	10.0	0.0	0.0	--
Headers	1	5.0	4.0	0.0	0.0	--
Heater/Treaters	1	8.0	20.0	0.0	0.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	29.0	42.0	0.0	2.0	1.0
Non-Low Production Oil with Associated Gas Well Site (>300 GOR) Model Plant						
Wellheads	2	10.0	8.0	0.0	2.0	--
Separators	1	6.0	10.0	0.0	0.0	--
Meters/Piping	2	26	96	1.0	1.0	--
Headers	1	5.0	4.0	0.0	0.0	--
Heater/Treaters	1	8.0	20.0	0.0	0.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	55.0	138.0	1.0	3.0	1.0

a. Data Source for average component count per equipment type: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h). Values were multiplied by the rounded equipment count for model plant component counts.

2.3.2 Low Production Well Site Model Plant Development

We created new model plants for well sites that have low production, where the average combined oil and natural gas production is less than 15 boe per day averaged over the first 30 days of production. Following promulgation of the 2016 NSPS OOOOa, information was received which contained component level emissions information for well sites in the Dallas/Fort Worth area (herein referred to as the "Fort Worth Study").[11] As part of the Fort Worth Study, total counts were provided for the number of wells, valves, connectors, storage vessels, compressors, separators, dehydrators, and other miscellaneous equipment, such as meter stations and heaters. Given the characteristics of the basin where these well sites are located, this information was only available for natural gas wells, including both dry and wet gas. We used the average count of major production and processing equipment that was reported for the 27 low production well sites as the basis for the natural gas well model plant for low production well sites. Because the fugitive emissions component counts were not available for each individual piece of major production and processing equipment, we used the average fugitive emissions component counts per major production and processing equipment obtained from the 1996 EPA/GRI Study.[12]

To create model plants for low production oil wells with <300 GOR and oil wells with associated gas (>300 GOR), we determined the difference between the non-low production and low production natural gas well site model plant fugitive emissions component counts, by dividing the component counts for the low production natural gas well sites by the component counts for the non-low production natural gas well sites. This scaling factor was applied to the non-low production oil and oil with associated gas well site model plants to create low production model plants for these types of well sites.

Additionally, consistent with the information presented in section 2.3.1, we included 1 controlled storage vessel per low production model plant and 2 wells per model plant. Therefore, the main difference between the non-low production and low production model plants is realized in the number of major production and processing equipment, other than controlled storage vessels. Table 2-2 includes the average fugitive emissions component counts for the low production well site model plants.

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[11] "The Natural Gas Air Quality Study (Final Report)", prepared by Eastern Research Group, Inc. July 13, 2011, available at *http://fortworthtexas.gov/gaswells/air-quality-study/final/*.

[12] The average fugitive emissions components per major production and processing equipment were calculated by summing the total quantity of equipment and dividing by the total number of sites for both Eastern & Western U.S. EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h).

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Table 2-2. Average Fugitive Emissions Component Count for Low Production Well Site Model Plants

Production Equipment	Model Plant Equipment Counts	Average Component Count Per Unit of Model Plant[a]				
		Valves	Connectors	OELs	PRVs	Thief Hatches
Low Production Natural Gas Well Site Model Plant						
Wellheads	2	19.0	74.0	2.0	0.0	--
Separators	2	43.0	137.0	8.0	3.0	--
Meters/Piping	1	13.0	48.0	1.0	0.5	--
In-Line Heaters	0	0.0	0.0	0.0	0.0	--
Dehydrators	1	24.0	90.0	2.0	2.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	100.0	349.0	12.0	5.0	1.0
Low Production Oil Well Site (<300 GOR) Model Plant						
Wellheads	2	8.0	6.0	0.0	2.0	--
Separators	1	5.0	8.0	0.0	0.0	--
Headers	1	4.0	3.0	0.0	0.0	--
Heater/Treaters	1	6.0	15.0	0.0	0.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	23.0	32.0	0.0	2.0	1.0
Low Production Oil with Associated Gas Well Site (>300 GOR) Model Plant						
Wellheads	2	8.0	6.0	0.0	1.0	--
Separators	1	5.0	8.0	0.0	0.0	--
Meters/Piping	2	20.0	72.0	1.0	1.0	--
Headers	1	4.0	3.0	0.0	0.0	--
Heater/Treaters	1	6.0	15.0	0.0	0.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	44.0	105.0	1.0	3.0	1.0

a. Data Source for average component count per equipment type: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h). Values were multiplied by the rounded equipment count for model plant component counts.

2.3.3 Wellhead Only Model Plant Development

We created model plants that consist of wellheads and no major production or processing equipment, for each of the 3 sub-types of well site model plants (*i.e.,* gas well, oil well, and oil with associated gas well sites). Each of these sub-types contain 2 wellheads each. We did not separate these by non-low production or low production because we assume the same number of wellheads for these well sites, regardless of production. The associated fugitive emissions components for these wellheads are summarized in Table 2-3.

Table 2-3. Average Fugitive Emissions Component Count for Wellhead Only Well Site Model Plants

Production Equipment	Model Plant Equipment Counts	Average Component Count Per Unit of Model Plant[a]				
		Valves	Connectors	OELs	PRVs	Thief Hatches
Natural Gas Well Site Model Plant						
Wellheads	2	19	74	2	0	0
Oil Well Site (<300 GOR) Model Plant						
Wellheads	2	10	8	0	2	0
Oil with Associated Gas Well Site (>300 GOR) Model Plant						
Wellheads	2	10	8	0	2	0

a. Data Source for average component count per equipment type: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h). Values were multiplied by the rounded equipment count for model plant component counts.

2.3.4 Compressor Station Model Plant Development

The 2016 NSPS OOOOa Final TSD evaluated fugitive monitoring at three types of compressor stations; gathering and boosting stations, transmission stations, and storage stations. The equipment associated with these compressor stations vary depending on the volume of natural gas that is transported and whether any treatment of the gas, such as the removal of water or hydrocarbons occurs. These sites include all equipment (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) that have associated components (*e.g.,* valves, connectors) that may be sources of fugitive emissions associated with these operations.

Gathering and Boosting Stations. Gathering and boosting stations are sites that collect oil and natural gas from well sites and direct this production fluid to the natural gas processing plant. These stations have similar production and processing equipment (including separators, meters, piping, compressors, in-line heaters, dehydrators, and other equipment) as what is included in the well site model plants; however, these stations are not directly connected to the wellhead. The 1996 EPA/GRI document

does not have specific information on major production and processing equipment counts for the gathering and boosting segment, but it does include fugitive emissions component counts for gathering compressors within the oil and natural gas production data. To estimate the additional major production and processing equipment at a gathering and boosting model plant, the weighted averages of major production and processing equipment counts for the Eastern and Western U.S. data sets for onshore production equipment were calculated. The weighted averages of the data sets were determined to be 11 separators, 7 meters/piping, 5 gathering compressors, 7 in-line heaters, and 5 dehydrators. These average equipment counts were used to create the model plant for gathering and boosting stations. The fugitive emissions components for gathering compressors were included in the model plant total counts, but the compressor seals were excluded because they are affected facilities subject to other standards within the 2016 NSPS OOOOa. Compressor seals are discussed in further details in Chapter 8 of the 2016 Final TSD. A summary are the fugitive emissions component counts for the oil and natural gas gathering and boosting station model plant are presented in Table 2-4. This model plant did not change from the model plant used in the 2016 NSPS OOOOa.

Table 2-4. Average Fugitive Emissions Component Count for Gathering and Boosting Station Model Plants

Production Equipment	Model Plant Equipment Counts	Average Component Count Per Model Plant[a]			
		Valves	Connectors	OELs	PRVs
Gathering and Boosting Stations					
Separators	11	242	748	44	11
Meters/Piping	7	91	336	0	0
Gathering Compressors	5	355	875	15	20
In-Line Heaters	7	98	455	14	7
Dehydrators	5	120	450	10	10
	Rounded Total	906	2,864	83	48

a. Data Source for average component count per equipment type: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h). Values were multiplied by the rounded equipment count for model plant component counts.

Natural Gas Transmission and Storage Station Model Plants. Natural gas transmission and storage stations are facilities that use compressors to move natural gas at elevated pressure from production fields or natural gas processing facilities, in transmission pipelines, to natural gas distribution pipelines, or into storage. In addition, transmission stations may include production equipment for liquids separation, natural gas dehydration, and storage vessels for the storage of water and hydrocarbon liquids.

Residue (sales) gas compressors operated by natural gas processing facilities are included in the onshore natural gas processing segment and are excluded from this segment.

The segments include fugitive emissions from fugitive emissions component related to the inlet and outlet pipelines, meter runs, dehydrators, and other piping located at the compressor building for transmission and storage stations, and injection/withdrawal components associated with the injection/withdrawal well piping at storage stations. This industry segment also includes emissions from compressor related components, but does not include emissions from compressor seals or site blowdown open-ended lines. As discussed in the 2016 Final TSD, blowdown open-ended lines were excluded from the analysis because these are considered vents and are not sources of fugitive emissions. Fugitive emissions component counts were obtained from the 1996 EPA/GRI study. A summary of the fugitive emissions component counts is presented in Table 2-5.

Table 2-5. Average Fugitive Emissions Component Count for Natural Gas Transmission and Storage Station Model Plants

Component	Model Plant Component Count[a]	
	Transmission Facility	Storage Facility
Valve	673	1,868
Control Valve	31	--
Connector	3,068	5,571
OEL	51	353
PRV	14	66
Valve (Injection/Withdrawal)	--	30
Connector (Injection/Withdrawal)	--	89
OEL (Injection/Withdrawal)	--	7
PRV (Injection/Withdrawal)	--	1

a. Data Source: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-17 and 4-24, June 1996. (EPA-600/R-96-080h)

2.3.5 Fugitive Emissions Estimation Method

Baseline model plant emissions were calculated using the fugitive emissions component counts from the GHG Inventory, derived from the Greenhouse Gas Reporting Program (GHGRP), 1996 EPA/GRI study, and 40 CFR part 98, subpart W tables as described above, the component oil and natural gas production emission factors from the *Protocol for Equipment Leak Emission Estimates* ("1995

Protocol) as incorporated into AP-42[13] for non-thief hatch fugitive emissions components. The emissions factor used for thief hatches on controlled storage vessels was derived from a study that conducted aerial surveys for emissions at oil and gas production sites located in seven basins across the U.S.[14] In this study, helicopter-based OGI monitoring was performed at 8,220 well sites. A total of 494 fugitive emission sources were identified at 327 sites, averaging approximately 1.5 fugitive sources per site. Fugitive emissions[15] from storage vessels accounted for 92 percent of the total fugitive sources, with 198 fugitive sources associated with storage vessel pressure relief valves (PRVs) and 257 fugitive sources associated with thief hatches. The estimated detection limit for the OGI instrument used by the study was 1 grams per second (g/s) for heavier hydrocarbons and 3 g/s for methane.[16] Based on this information, we used the 1 g/s estimated emission rate in combination with the frequency of storage vessel emissions identified in the study to estimate emissions from thief hatches for purposes of the model plants. Annual emissions were calculated assuming 8,760 hours of operation each year. The emissions factors are provided for total organic compounds (TOC) and include non-VOCs such as methane and ethane. The TOC emissions were converted to methane and VOC using methane/TOC and VOC/TOC weight rations as described in the 2011 Gas Composition Memorandum developed for the 2012 NSPS.[17] The emission factors presented in Table 2-6 were used to estimate the emissions from well sites, gathering and boosting stations, and natural gas transmission and storage stations. Table 2-7 summarizes the methane emissions factor for each component type in the transmission and storage station model plants. Table 2-8 summarizes the calculated baseline fugitive emissions for each of these model plants.

[13] U.S. EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)
[14] Lyon, David R., et al., *Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites*. Environmental Science and Technology 2016, 50, 4877-4886.
[15] It was difficult for the Lyon, David R., et al., study to attribute emissions from storage vessels to specific malfunctions or normal operations. The study predicted liquid unloading events and stuck open separator dump valves would contribute less than 0.1% of the emissions detected for each event. The other 99.8% of the storage vessel emissions were not characterized by the study. See *Id.* At pages 4882-4883.
[16] *Id.*
[17] Memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. "Composition of Natural Gas for use in the Oil and Natural Gas Sector Rulemaking". July 2011. Docket ID No. EPA-HQ-OAR-2010-0505-0084.

Table 2-6. Oil and Natural Gas Average TOC Emissions Factors

Component Type	Component Service	Uncontrolled Emissions Factor[a] (kg/hr/component)
Valves	Gas	4.5E-03
Flanges	Gas	3.9E-04
Connectors	Gas	2.0E-04
OEL	Gas	2.0E-03
PRV	Gas	8.8E-03
Thief Hatches[b]	--	0.1296

a. Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)
b. Thief hatch emission factors are based on information obtained from Lyon, D., et al. "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," Environ. Sci. Technol. 2016, 50, 4877-4886. We have used 1g/s for emissions from thief hatches and tank vents because the study represents this as the minimum detection limit for these sources which have emissions composed primarily of higher hydrocarbons and adjusted this value to account for the percentage of storage vessels identified with fugitive emissions during the study (3.6%) .

Table 2-7. Oil and Natural Gas Transmission and Storage Average Methane Emissions Factors

Component Type	Component Methane Emissions Factor[a] (Mscf/year/component)
Transmission Facility	
Valves	0.867
Control Valve	8
Connectors	0.147
OEL	11.2
PRV	6.2
Storage Facility	
Valve	0.867
Connector	0.147
OEL	11.2
PRV	6.2
Valve (Injection/Withdrawal)	0.918
Connector (Injection/Withdrawal)	0.125
OEL (Injection/Withdrawal)	0.237
PRV (Injection/Withdrawal)	1.464

a. Data source: EPA/GRI, Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Tables 4-17 and 4-24, June 1996. (EPA-600/R-96-080h)

Table 2-8a. Estimated Baseline Fugitive Emissions for the Well Site Model Plants[a]

Model Plant Component Type	Model Plant Component Count	Uncontrolled Emissions Factor[a] (kg/hr/component)	Uncontrolled Emissions (tpy)	
			Methane[b]	VOC[c]
Non-Low Production Gas Well Site				
Valves	127	4.5E-03	3.83	1.06
Flanges	0	3.9E-04	0.00	0.00
Connectors	462	2.0E-04	0.62	0.17
OEL	14	2.0E-03	0.19	0.05
PRV	7	8.8E-03	0.41	0.12
Thief Hatch	1	0.1296	0.87	0.24
		Total	5.91	1.64
Non-Low Production Oil Well Site				
Valves	29	4.5E-03	0.87	0.24
Flanges	54	3.9E-04	0.14	0.04
Connectors	42	2.0E-04	0.06	0.02
OEL	0	2.0E-03	0.00	0.00
PRV	2	8.8E-03	0.12	0.03
Thief Hatch	1	0.1296	0.87	0.24
		Total	2.06	0.57
Non-Low Production Oil w/Associated Gas				
Valves	55	4.5E-03	1.7	0.46
Flanges	54	3.9E-04	0.14	0.04
Connectors	138	2.0E-04	0.19	0.05
OEL	1	2.0E-03	0.01	0.00
PRV	3	8.8E-03	0.18	0.05
Thief Hatch	1	0.1296	0.87	0.24
		Total	3.0	0.85
Low Production Gas Well Site				
Valves	100	4.5E-03	3.01	0.84
Flanges	0	3.9E-04	0.00	0.0
Connectors	349	2.0E-04	0.47	0.13
OEL	12	2.0E-03	0.16	0.05
PRV	5	8.8E-03	0.30	0.08
Thief Hatch	1	0.1296	0.87	0.24
		Total	4.80	1.34
Low Production Oil Well Site				
Valves	23	4.5E-03	0.69	0.19
Flanges	41	3.9E-04	0.11	0.03
Connectors	32	2.0E-04	0.04	0.01
OEL	0	2.0E-03	0.00	0.00
PRV	2	8.8E-03	0.12	0.03
Thief Hatch	1	0.1296	0.87	0.24
		Total	1.83	0.51

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Model Plant Component Type	Model Plant Component Count	Uncontrolled Emissions Factor[a] (kg/hr/component)	Uncontrolled Emissions (tpy)	
			Methane[b]	VOC[c]
Low Production Oil Well Site w/Associated Gas				
Valves	44	4.5E-03	1.33	0.37
Control Valves	41	3.9E-04	0.11	0.03
Connectors	105	2.0E-04	0.14	0.04
OEL	1	2.0E-03	0.01	0.00
PRV	3	8.8E-03	0.18	0.05
Thief Hatch	1	0.1296	0.87	0.24
		Total	2.63	0.73
Natural Gas Wellhead Only				
Valves	19	4.5E-03	0.57	0.16
Flanges	0	3.9E-04	0.00	0.00
Connectors	75	2.0E-04	0.10	0.30
OEL	2	2.0E-03	0.03	0.00
PRV	0	8.8E-03	0.00	0.00
		Total	0.7	0.19
Oil Wellhead Only				
Valves	10	4.5E-03	0.3	0.08
Flanges	20	3.9E-04	0.05	0.02
Connectors	8	2.0E-04	0.01	0.00
OEL	0	2.0E-03	0.00	0.00
PRV	2	8.8E-03	0.12	0.03
		Total	0.48	0.13
Oil Well w/Associated Gas Wellhead Only				
Valves	10	4.5E-03	0.3	0.08
Flanges	20	3.9E-04	0.05	0.02
Connectors	8	2.0E-04	0.01	0.00
OEL	0	2.0E-03	0.00	0.00
PRV	2	8.8E-03	0.12	0.03
		Total	0.48	0.13

a. Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017) for TOC emissions factors for components in gas service.
b. Methane emissions calculated using 0.695 weight ratio for methane/TOC for well sites and gathering and boosting obtained from the 2011 Gas Composition Memorandum.
c. VOC emissions calculated using 0.193 weight ratio for methane/TOC for well sites obtained from the 2011 Gas Composition Memorandum.

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Table 2-8b. Estimated Baseline Fugitive Emissions for the Compressor Station Model Plants[a]

Model Plant Component Type	Model Plant Component Count	Uncontrolled Emissions Factor[a]	Uncontrolled Emissions (tpy)	
			Methane[b]	VOC[c]
Gathering and Boosting Station				
		kg/hr/component		
Valves	906	4.5E-03	27.35	7.603
Flanges	0	3.9E-04	0.0	0.0
Connectors	2,864	2.0E-04	3.84	1.07
OEL	83	2.0E-03	1.11	0.31
PRV	48	8.8E-03	2.83	0.79
		Total	35.14	9.77
Transmission Station				
		Mscf/year/component		
Valves	673	0.867	12.1	0.34
Control Valves	31	8	5.2	0.14
Connectors	3,068	0.147	9.4	0.26
OEL	51	11.2	11.9	0.33
PRV	14	6.2	1.8	0.05
		Total	40.4	1.12
Storage Station				
		Mscf/year/component		
Valves	1,868	0.867	33.71	0.93
Connectors	5,571	0.147	17.05	0.47
OEL	353	11.2	82.29	2.28
PRV	66	6.2	8.52	0.24
Valves (Injection/Withdrawal)	30	0.918	0.57	0.02
Connectors (Injection/Withdrawal)	89	0.125	0.23	0.01
OEL (Injection/Withdrawal)	7	0.237	0.03	0.00
PRV (Injection/Withdrawal)	1	1.464	0.03	0.00
		Total	142.4	3.94

a. Data Source: EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017) for TOC emissions factors for components in gas service.
b. Methane emissions calculated using 0.695 weight ratio for methane/TOC for gathering and boosting obtained from the 2011 Gas Composition Memorandum. Methane emissions for transmission and storage were calculated by multiplying the model plant component count by the component methane emission factor and converting to tons using the conversion factor 0.02082 tons methane/Mscf methane.
c. VOC emissions calculated using 0.193 weight ratio for methane/TOC for gathering and boosting obtained from the 2011 Gas Composition Memorandum. VOC emissions calculated using 0.0277 weight ratio for VOC/methane for transmission and storage obtained from the 2011 Gas Composition Memorandum.

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2.4 Control Techniques

As shown in the 2016 TSD, the EPA has previously evaluated the cost of using OGI or Method 21 for detection of fugitive emissions in its BSER analysis for reducing fugitive emissions at well sites and compressor stations. In the 2016 NSPS OOOOa, the EPA determined OGI to be the BSER but provided Method 21 as an alternative.[18] Based on a review of various state regulations,[19] OGI and Method 21 remain the main detection technologies for identifying fugitive emissions, and none of the petitions for reconsideration identify any specific new detection technologies or control techniques for us to evaluate as BSER. Therefore, for purposes of this reconsideration, we did not evaluate other detection technologies or control techniques. However, we did evaluate the use of OGI and Method 21 at various monitoring frequencies for each of the updated or newly developed model plants. The following sections describe our evaluation of the potential emission reductions and cost of control for a fugitive emissions monitoring and repair program using either OGI or Method 21.

2.4.1 Fugitive Emissions Detection and Repair with OGI

The reduction of fugitive emissions from well sites and compressor stations (*i.e.,* gathering and boosting stations, transmission stations, and storage facilities) involves the development of a fugitive emissions monitoring plan. As described in the proposed reconsideration, the company develops and implements a monitoring plan that covers the collection of fugitive emissions components at well sites or compressor stations within a company defined area. The monitoring plan would include inspection of the collection of all fugitive emissions components, such as valves, connectors, open-ended lines/valves, pressure relief devices, closed vent systems, compressors, and thief hatches on controlled storage vessels. The plan would include provisions to repair or replace fugitive emissions components if evidence of fugitive emissions is discovered during the OGI survey (*e.g.,* any visible emissions from a fugitive emissions component observed using OGI).

In order to estimate the cost of implementation of a monitoring and repair plan, the EPA estimated the cost of repair, which is based on the number of components found to have fugitive emissions. Since OGI visualizes gaseous emissions using active or passive infrared imaging, the OGI operator is not able to determine the exact concentration or emission rate of the fugitive emissions; however, all visualized fugitive emissions are subject to requirements for repair. If a fugitive emissions component cannot be

[18] 81 FR 35846.

[19] See memorandum *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 12, 2018.

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immediately repaired during the monitoring survey, the operator must repair the component as soon as practicable, but no later than 60 days after detection of the fugitive emissions. A first attempt at repair is required within 30 days after detection of the fugitive emissions. Repair is not considered complete until the fugitive emissions component has been resurveyed to verify the repair was successful. For this resurvey, the operator may use OGI, Method 21 or the alternative screening procedures specified in section 8.3.3 of Method 21 to confirm that the component is no longer emitting fugitive emissions. When OGI is used for the resurvey, no visible emissions indicate that the fugitive emissions component has been repaired. When Method 21 is used for the resurvey, no detectable emissions (*e.g.*, a concentration of less than 500 ppm above background) indicate that the fugitive emissions component has been repaired.

2.4.1.2 OGI Emission Reduction Potential

Information in the white paper on oil and natural gas leaks[20] related to the potential emission reductions from OGI monitoring and repair varied from 40 to 99 percent. The data from these studies are based on the gathering of individual OGI surveys at various oil and natural gas segment sites. The variation in the percent reductions from these OGI surveys generally depended on whether large fugitive emission sources were found during the OGI survey and assumptions made by the authors. However, these studies in the white paper did not provide information on the potential emission reductions from the implementation of an annual, semiannual, quarterly or monthly OGI monitoring and repair program. A report was found after the publication of the white paper from the Colorado Air Quality Control Commission[21] which estimated 40 percent reduction for annual OGI monitoring for well production tank batteries with an uncontrolled VOC emissions of greater than 6 tpy or less than or equal to 12 tpy (≥ 6 to $\leq$ 12 tpy), 60 percent reduction for quarterly OGI monitoring for well production tank batteries with an uncontrolled VOC emissions of greater than 12 tpy and less than or equal to 50 tpy (> 12 to ≤ 50 tpy), and 80 percent reduction for monthly OGI monitoring at well production tank batteries with an uncontrolled VOC emission greater than 50 tpy (> 50 tpy).

From the review of the studies in the white paper and the Colorado Economic Impact Analysis, the EPA expects the emission reductions from the implementation of an OGI monitoring and repair program to vary depending on the frequency of monitoring. As noted above, Colorado estimated that monthly monitoring would achieve 80 percent at well production tank batteries with an uncontrolled VOC emission

[20] U.S. EPA Office of Air Quality Planning and Standards, *Oil and Natural Gas Sector Leaks*, located at https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-5110. April 2014.
[21] Colorado Air Quality Control Commission, *Cost-Benefit Analysis for Proposed Revisions to Regulation Number 3 and 7 (5 CCR 1001-5 and 5 CCR 1001-9)*. February 7, 2014.

rate of greater than 50 tpy. We believe, based on our review of the studies, monthly monitoring should achieve much higher emission reductions.

Data from the EPA Protocol document estimates monthly Method 21 monitoring to achieve 87 percent reductions at a leak definition of 10,000 ppm and 92 percent reductions at a leak definition of 500 ppm. Potential emissions reductions for annual, semiannual, and quarterly monitoring frequencies[22] were calculated using the data from the EPA Protocol document. For quarterly monitoring, the Method 21 data from the EPA Protocol document estimates a 67 percent reduction at a leak definition of 10,000 ppm and an 83 percent reduction at a leak definition of 500 ppm. Using Method 21 data from the EPA Protocol document, we estimated the percent reductions from semiannual monitoring to be 55 percent at a leak definition of 10,000 ppm and 75 percent reduction at a leak definition of 500 ppm. The potential emission reduction percentages for annual monitoring were calculated to be 42 percent at a leak definition of 10,000 ppm and 68 percent at a leak definition of 500 ppm.

OGI equipment meeting the requirements of 40 CFR 60.5397a(c)(7)(i) are capable of viewing fugitive emissions located at oil and natural gas well sites and compressor stations. The sensitivity (*i.e.,* detection limit) of the currently available OGI equipment varies based on changes in the fugitive compound(s) being imaged, ambient conditions (*i.e.,* sky condition, wind speed, and background temperature), distance of the operator from the fugitive emissions source, and the visual acuity of the operator. Because of the subjectivity of the measurement and variability in typical field ambient conditions, it is not possible to correlate OGI detection capabilities with a Method 21 instrument reading, provided in ppm. However, based on our 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]

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[22] Memorandum to Jodi Howard, U.S. EPA from Bradley Nelson, EC/R, "Estimation of Potential Emission Reductions with the Implementation of a Method 21 Monitoring Program". April 2016. Docket ID No. EPA-HQ-OAR-2010-0505-7625.

[23] Note: EPA previously stated that "the OGI camera is capable of viewing leaks at a 500 ppm level" in the 2016 Final TSD. While EPA agrees that in a controlled laboratory setting under optimal conditions, OGI equipment may be capable of detecting concentrations of this magnitude, it is unlikely that this magnitude of leak would be visible in a field setting. We acknowledge this in the preamble to the 2016 NSPS OOOOa, "At this threshold [500 ppm], the operator would have to repair every component found to have fugitive emissions over 500 ppm threshold. This results in emission reductions greater than the emission reductions that would be achieved if OGI were used instead." 81 FR 35857. For more information on the detection capability of OGI equipment, see https://www.regulations.gov/document?D=EPA-HQ-OAR-2010-0505-4949.

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A study performed by ICF[24] using data from Subpart W, EPA/ GRI, City of Fort Worth Natural Gas Air Quality Study, UT Study - Methane Emissions in the Natural Gas Supply Chain: Production, UT Study - Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States Pneumatic Controllers and Jonah Energy LLC WCCA Spring Meeting Presentation determined that the Year 3 fugitive emissions reductions from a quarterly LDAR program to be 78 percent. The data provided in the study supports 40, 60, 80 percent emission reductions for annual, semiannual and quarterly monitoring, respectively.

On the basis of the analysis and the data described here, it was concluded that an OGI monitoring program in combination with a repair program can reduce fugitive methane and VOC emissions from these segments by 40 percent on an annual frequency, 60 percent on a semiannual frequency and 80 percent on a quarterly frequency as well as minimize the loss of salable gas.

In addition to the quarterly, semiannual, and annual monitoring frequencies, we evaluated a stepped down monitoring frequency for well sites that would require semiannual monitoring for the 2-year period following the initial monitoring, followed by annual monitoring from that point forward. One petitioner asserted that the EPA's cost-effectiveness analysis was not accurate and should be revised.[25] In support, the petitioner provided data (which is described in more detail below). The petitioner suggested that, at a minimum, the EPA should require semiannual monitoring at well sites for an initial period of 2 years followed by less frequent monitoring frequencies such as annual monitoring for sites that do not have a significant number of "leaking"[26] components.[27] To evaluate the emission reduction potential of the OGI monitoring and repair program at this stepped frequency, we limited the analysis to the first 8 years of applicability because our cost estimates, described later in this document, consider the impacts for an 8-year period. We applied the 60 percent emission reduction for semiannual monitoring for 2 years and the 40 percent emission reduction for annual monitoring for 6 years, then annualized this percentage to determine the emission reduction of the stepped monitoring frequency of 45 percent.

For low production well sites we also evaluated monitoring once every other year (*i.e.*, biennial monitoring). To evaluate the emission reduction potential of the OGI monitoring and repair program at biennial monitoring, we estimated the percent reduction achieved at a biennial monitoring frequency with

[24] ICF International, Leak Detection and Repair Cost-Effectiveness Analysis, Prepared for Environmental Defense Fund, December 4, 2015, Revised May 2, 2016. Available at https://www.edf.org/sites/default/files/content/edf_ldar_analysis_120415_v7.pdf.
[25] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.
[26] While the petitioner used the term leaking, the EPA is clarifying they were referring to fugitive emissions, and not equipment leaks such as those subject to a leak detection and repair (LDAR) program at onshore natural gas processing plants.
[27] See Docket ID No. EPA-HQ-OAR-2010-0505-7682.

a 10,000 ppm leak definition using Method 21. This analysis resulted in a 30 percent emission reduction for biennial monitoring.

2.4.1.3 Cost Impacts of OGI-Based Program

Costs for preparing an OGI fugitive emission monitoring and repair plan for a company defined area (*i.e.,* field or district) were estimated using hourly estimates for each of the monitoring and repair plan elements. The costs are based on the following assumptions (costs are presented in 2016$):

- Labor cost for each of the monitoring plan elements, such as reading the rule, was estimated to be $61.21 per hour.
- Reading of the rule and instructions would take 1 person 4 hours to complete at a cost of $245.
- Development of a fugitive emission monitoring plan would take 2.5 people a total of 60 hours to complete at a cost of $3,672.
- Initial activities planning are estimated to take 2 people a total of 8 hours per person for each monitoring event. Cost for biennial monitoring was estimated to be $490, annual monitoring was estimated to be $979, semiannual monitoring was estimated to be $1,959, and stepped monitoring $1,224 for well sites. For compressor stations, the initial activities planning cost are estimated at $1,959 for all monitoring frequencies.
- Notification of compliance status was estimated to take 1 person 1 hour to complete at a cost of $61.21 per well site and compressor stations. We estimated that 22 well sites within each company-defined area for a total of $1,347 for well sites. We estimated 7 gathering and boosting stations per company for a total of $428 and 1 transmission or storage station per notification for a total of $61.21 per transmission and storage station.

Costs for implementing a fugitive emission monitoring plan for a company defined area (*i.e.,* field or district) were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

- Subsequent activities planning are estimated to take 2 people a total of 8 hours per person to complete at a cost of $979 per monitoring event for well sites. For oil and natural gas production well sites, this cost was divided among the total number of well sites owned in a company defined area, which was assumed to be 22. The cost per well site was estimated to be $45 per monitoring event. For compressor stations, the subsequent activities planning are estimated to take 2 people 12 hours per person to complete at a cost of $1,469.

- The cost for OGI monitoring using an outside contractor was assumed to be $635 for a well site for each monitoring event and $2,300 for each compressor station monitoring event.[28]
- Annual repair costs were estimated to be $316 per monitoring event for well sites, $3,638 per monitoring event for gathering and boosting stations, $3,559 per monitoring event for transmission stations, and $7,355 per monitoring event for storage stations. These costs were estimated assuming that 1.18 percent of the components are identified with fugitive emissions[29] during monitoring and 75 percent are repaired online and 25 percent are repaired offline.
- Costs to resurvey the repaired components that could not be fixed during the initial survey using a Method 21 device was estimated using a resurvey time of 5 minutes per leak at a cost of $61.21 per hour. This assumes the company is able to perform the resurvey without retaining contractors.
- Preparation of annual reports was estimated to take 1 person a total of 4 hours to complete at a cost of $245.

The initial setup cost or capital cost for oil and natural gas well sites was calculated by summing up the costs for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, and notification of initial compliance status. In 2016, we assumed that each company defined area would require the purchase of an instrument to perform Method 21 monitoring for the resurvey. However, it is our understanding that if repairs are not made during the monitoring event, OGI or the alternative method in section 8.3.3 of Method 21 (soap solution) are used instead. Therefore, the cost estimates were updated to remove the capital cost of purchasing a Method 21 instrument.

The total capital cost of these activities was calculated to be ~~$6,243~~5,753 per company defined area for biennial monitoring, $6,243 for annual monitoring, $6,488 for the stepped monitoring, and $7,222 for semiannual monitoring. Assuming that each company owns and operates 22 well sites within a company defined area[30], the capital cost per well site was estimated to be $262 for biennial monitoring, $284 for annual monitoring, $295 for stepped monitoring, and $328 for semiannual monitoring. For gathering and boosting compressor stations the capital cost for reading the rule, development of fugitive emissions monitoring plan, and initial activities planning notification of initial compliance status was calculated to be

[28] Costs for contractor based OGI monitoring obtained from the Carbon Limits report.

[29] The assumption of 1.18% leak rate for OGI monitoring was obtained from Table 5 of the Uniform Standards memorandum. The 1.18% value is the baseline leak frequency for valves in gas/vapor service. None of the other baseline frequencies in this table were used because the equipment are in liquid service (*e.g.*, pumps LL, valve LL, agitators LL). There is no information on the number of leaks located at uncontrolled facilities, only average percentages of the total number of components at a facility. Therefore, our methodology was to use the 1.18% leak frequency value from the Uniform Standards memorandum and apply that value to the total number of components at the oil and natural gas model plant. (Uniform Standards Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180).

[30] The number of well sites owned and operated by companies was calculated using data from the Fort Worth study.

$6,304, which was assumed to be shared between 7 gathering and boosting stations within the company defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210 mile radius of a central location, the capital cost of each of these stations was estimated to be $901. For transmission and storage stations, the capital cost per facility was calculated to be $5,937.

For all oil and natural gas segments, the annual cost includes subsequent activities planning, OGI survey, cost of repair of fugitive emissions found, resurvey of repaired components, preparation and submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. For our analysis the EPA calculated the annual cost for annual, stepped, and semiannual OGI surveys at well sites, and annual, semiannual, and quarterly OGI surveys at compressor stations. The annual cost for the biennial monitoring frequency was estimated by assuming the annual monitoring frequency values were incurred during the years when monitoring takes place and no annual cost in the years when monitoring does not occur. The OGI monitoring cost memorandum[31] presented in 2016 contains the analyses for other costing methodologies, including a company-based OGI monitoring program and an OGI program using cost methodologies developed for the Colorado fugitive leak program to estimate the annual cost of implementing an OGI monitoring and repair program for oil and natural gas well sites, gathering and boosting, transmission and storage compressor stations for the respective OGI monitoring frequencies. This memorandum was not updated for this reconsideration.

The cost per ton of emissions reduced was calculated using two separate methods. The first method allocated all of the costs to one pollutant and zero to the other (single-pollutant approach) using representative unit costs for each control option. The second method allocated the annual cost among the pollutants (*i.e.,* GHG (in the form of limiting methane emissions) and VOC) that a given technology reduced (multi-pollutant approach). This proration was based on estimates of the percentage reduction expected for each pollutant. In the case of fugitives, the percent reductions for methane and VOC emissions are equal; and therefore, the proration of the annual cost was divided equally and applied to the methane and VOC reductions.

Based on estimated emissions reductions and the estimated cost for implementing an OGI fugitive emissions monitoring and repair program at the affected facilities, the EPA calculated a cost of control for methane and VOC for the various options for oil and natural gas production well sites, gathering and boosting, and transmission and storage compressor stations. The EPA then calculated the cost of control of

[31] Memorandum to Jodi Howard, U.S. EPA from Bradley Nelson, EC/R. "Evaluation of Cost methodologies for OGI Monitoring". April 2016. Docket ID No. EPA-HQ-OAR-2010-0505-7624.

well sites and compressor stations using the weighted average cost of control for all well sites and all compressor stations (*i.e.,* gathering and boosting, transmission and storage). Tables 2-9, 2-10, 2-11, 2-12, and 2-~~12~~13 present a summary of the cost of control for methane and VOC for the various OGI monitoring frequency options (*i.e.,* biennial, annual, semiannual, stepped, and quarterly, respectively).

2.4.1.4 Secondary Impacts

No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of fugitive emissions components. There are some emissions that would be generated by the OGI camera monitoring contractors with respect to driving to and from the site for the fugitive emissions survey. Using AP-42 mobile emission factors[32] and assuming a distance of 70 miles to the well site or compressor station, the emissions generated from semiannual monitoring at a well site (140 miles to and from the well site twice a year) is estimated to be 0.35 pounds per year (lb/yr) of hydrocarbons, 6.0 lb/yr of carbon monoxide (CO) and 0.40 lb/yr of nitrogen dioxides (NO_X). The emissions generated from quarterly monitoring at a compressor station (140 miles to and from the compressor station four times a year) is estimated to be 0.70 lb/yr of hydrocarbons, 12.0 lb/yr of CO and 0.80 lb/yr of NO_X.

Table 2-9. Summary of the Model Plant Cost of Control for Biennial OGI Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	Methane	VOC	Methane	VOC
Single Pollutant Approach				
Low Production Well Site Program	$1,104	$3,972	$906	$3,259
Multipollutant Approach				
Low Production Well Site Program	$552	$1,986	$453	$1,629

a. The weighted average for the segments were calculated using the 2014 activity counts of 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), and 1,222 low production oil well sites (GOR>300).
b. Recovery credits for oil and natural gas production well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42 Mcf.

[32] AP-42: Compilation of Air Pollutant Emission Factors. Highway Vehicles, Light-Duty Gasoline Truck I, Model Year 1998+, 50,000 miles. https://www3.epa.gov/otaq/ap42.htm#highway.

Table 2-10. Summary of the Model Plant Cost of Control for Annual OGI Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	Methane	VOC	Methane	VOC
Single Pollutant Approach				
Non-Low Production Well Site Program	$979	$3,523	$781	$2,810
Low Production Well Site Program	$1,360	$4,893	$1,140	$4,102
Compressor Station Program	$557	$2,414	$396	$1,717
Multipollutant Approach				
Non-Low Production Well Site Program	$490	$1,761	$391	$1,405
Low Production Well Site Program	$680	$2,446	$570	$2,051
Compressor Station Program	$278	$1,207	$198	$859

a. The weighted average for the segments were calculated using the 2014 activity counts of 2,001 non-low production gas well sites, 1,848 non-low production oil well sites (GOR<300), 9,190 non-low production oil well sites (GOR>300), 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), 1,222 low production oil well sites (GOR>300), 212 G&B stations, 36 transmission stations, and 2 storage facilities.
b. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42 Mcf.
Note: Transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

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Table 2-~~10~~11. Summary of the Model Plant Cost of Control for Semiannual OGI Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	Methane	VOC	Methane	VOC
Single Pollutant Approach				
Non-Low Production Well Site Program	$1,164	$4,186	$965	$3,473
Low Production Well Site Program	$1,616	$5,814	$1,396	$5,023
Compressor Station Program	$652	$2,827	$491	$2,130
Multipollutant Approach				
Non-Low Production Well Site Program	$582	$2,093	$483	$1,736
Low Production Well Site Program	$808	$2,907	$698	$2,512
Compressor Station Program	$326	$1,413	$246	$1,065

a. The weighted average for the segments were calculated using the 2014 activity counts of 2,001 non-low production gas well sites, 1,848 non-low production oil well sites (GOR<300), 9,190 non-low production oil well sites (GOR>300), 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), 1,222 low production oil well sites (GOR>300), 212 G&B stations, 36 transmission stations, and 2 storage facilities.
b. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42 Mcf.
Note: Transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

Table 2-~~11~~12. Summary of the Model Plant Cost of Control for Stepped OGI Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	Methane	VOC	Methane	VOC
Single Pollutant Approach				
Non-Low Production Well Site Program	$1,041	$3,744	$842	$3,031
Low Production Well Site Program	$1,445	$5,200	$1,247	$4,487
Multipollutant Approach				
Non-Low Production Well Site Program	$520	$1,872	$421	$1,515
Low Production Well Site Program	$723	$2,600	$624	$2,243

a. The weighted average for the segments were calculated using the 2014 activity counts of 2,001 non-low production gas well sites, 1,848 non-low production oil well sites (GOR<300), 9,190 non-low production oil well sites (GOR>300), 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), and 1,222 low production oil well sites (GOR>300).
b. Recovery credits for oil and natural gas production well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42 Mcf.

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Table 2-~~12~~13. Summary of the Model Plant Cost of Control for Quarterly OGI Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	Methane	VOC	Methane	VOC
Single Pollutant Approach				
Compressor Station Program	$910	$3,946	$749	$3,250
Multipollutant Approach				
Compressor Station Program	$455	$1,973	$375	$1,625

a. The weighted average for the segments were calculated using the 2014 activity counts of 21 G&B stations, 36 transmission stations, and 2 storage facilities.
b. Recovery credits for gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42 Mcf.

2.4.2 Fugitive Emissions Detection and Repair with Method 21

In the 2016 NSPS OOOOa, we allowed owners and operators the option to perform fugitive emissions monitoring using Method 21 instead of OGI. Under this option, the reduction of fugitive emissions from well sites and compressor stations also involves the development of a fugitive emissions monitoring plan, except that the monitoring is conducted using Method 21 instead of OGI, as described in section 2.4.1. The Method 21 monitoring includes the development of a fugitive emissions monitoring plant, survey using Method 21 instrumentation, resurvey of components to verify successful repair, and the preparation and submittal of an annual report. The monitoring plan must include an inventory of fugitive emissions components, including information on the component type, type of service (*e.g.,* gas/vapor, light liquid, or heavy liquid), location of the component, and information about each monitoring event specific to the individual component. Additionally, provisions for the repair and resurvey must be included in the monitoring plan. For our analysis, we evaluated two repair thresholds, or instrument readings that would trigger the repair requirements: 500 ppm and 10,000 ppm. Options to reduce emissions under the Method 21 detection option will vary based on the frequency of monitoring and the instrument reading that triggers repair.

2.4.2.1 Method 21 Emission Reduction Potential

The EPA based the emission reduction analysis on the method for estimating leak detection and repair (LDAR) control effectiveness from Chapter 5.3.1 of the Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017). Under this method, the control effectiveness is calculated using a stepwise approach that starts from the initial leak frequency and adds monitoring cycles until the leak

frequency after monitoring reaches steady state. The difference between the initial leak rate and the final leak rate provides the control effectiveness for the fugitive emissions monitoring program. Other parameters included in the monitoring cycle calculations are the percentage of successfully repair components, the percentage of new leaks and the percentage of leaks that were repaired but have reoccurred. The EPA Protocol does not provide these data for oil and natural gas production; only for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) and refineries. The refinery emissions data are provided in non-methane organic compound (NMOC) units, which would require assumed TOC and methane weight fractions to determine the TOC emission factors, whereas the SOCMI emissions data is already based on TOC. The assumed TOC and methane weight fractions would add another level of uncertainty to the emission reduction percentage calculations if the refinery data were used. Therefore, we determined that using the SOCMI data would provide the best estimate of potential fugitive emission reduction percentages for a typical Method 21 monitoring program, and would be comparable to the potential fugitive emission reductions for oil and gas production, if the other parameters were available for this segment. The potential emission reduction from the implementation of a Method 21 program was calculated using this SOCMI data. Table 2-~~12~~14 provides a summary of the parameters used to calculate the monitoring cycles. An example of the methodology is provided in Chapter 5.3.2 of the EPA Protocol document. The SOCMI data in the EPA Protocol document only included occurrence rates for monthly and quarterly monitoring. To calculate annual and semiannual occurrence rates, a logarithmic equation was derived from the data points. Initial leak frequencies were calculated using the EPA Protocol average leak rate equations for 500 and 10,000 ppm gas valves (see Table 5-4 of the EPA Protocol) and the average SOCMI emission factor for gas valves of 0.00597 kilograms per hour per source (see Table 2-1 of the EPA Protocol) and solving for leak fraction. The initial leak frequencies can also extrapolated using the lines in Figure 5-1 in the EPA Protocol document. The average leak fraction equation and calculated initial leak frequency are provided in Table 2-~~13~~14.

Using the parameters in Table 2-~~13~~14, the estimated emission reductions were calculated using the monitoring cycle approach in the EPA Protocol document. The leak frequency after monitoring reached steady state on the sixth monitoring cycle and the percent reduction was calculated. The results of the emission reductions are presented in Table 2-~~14~~15.[33]

[33] See memorandum *Estimation of Potential Reductions with the Implementation of a Method 21 Monitoring Program*, located at Docket ID No. EPA-HQ-OAR-2010-0505-7625.

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Table 2-~~13~~14. Parameters and Assumptions Used to Calculate Monitoring Cycles

Parameter	Parameter Value (500 ppm)	Parameter Value (10,000 ppm)
Occurrence Rate	5.46% Annual 4.21% Semiannual 2.97% Quarterly	5.46% Annual 4.21% Semiannual 2.97% Quarterly
Recurrence Rate	14%	14%
Unsuccessful Repair Rate	10%	10%
Initial Leak Frequency	13.53%	7.49%
Average Leak Rate Equation	ALR = 0.044*LF + 0.000017	ALR = 0.078*LF + 0.00013

Table 2-~~14~~15. Percent Reduction in Emissions for EPA Method 21 Monitoring and Repair

Monitoring Frequency	Fugitive Percent Reduction		
	Method 21 Repair Threshold		OGI
	10,000 ppm	500 ppm	
Biennial	30	61	30
Annual	42	68	40
Stepped	45	70	45
Semiannual	55	75	60
Quarterly	67	83	80

As noted in Table 2-~~14~~15 above, in all cases the percent reduction for the 500 parts per million Method 21 alternative is equal to or greater than the estimated OGI monitoring and repair percent reduction. The percent reduction for the 10,000 parts per million leak threshold was only greater than the OGI option for annual monitoring. Based on the estimated OGI monitoring model plant emission reductions (see Tables 2-9 through 2-~~12~~13), Table 2-15 summarizes the estimated model plant emission reductions for the alternative Method 21 monitoring and repair option for 500 and 10,000 ppm leak thresholds. ~~For annual monitoring, both the Method 21 leak thresholds had higher emission reductions then the OGI monitoring option. Only the 500 ppm leak threshold had emission reductions that were equal to or greater than the OGI monitoring option for semiannual and quarterly monitoring.~~

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Table 2-~~15a~~16a. Model Plant Emission Reductions for OGI and EPA Method 21 Monitoring and Repair – Well Sites

Affected Facility	OGI Monitoring (tpy)		Method 21 10,000 ppm (tpy)[a]		Method 21 500 ppm (tpy)[a]	
	Methane	VOC	Methane	VOC	Methane	VOC
Annual Monitoring						
Gas Well Sites	2.36	0.66	2.49	0.69	4.04	1.12
Oil Well Sites (GOR < 300)	0.82	0.23	0.87	0.24	1.40	0.39
Oil Well Sites (GOR > 300)	1.22	0.34	1.28	0.36	2.08	0.58
Low Production Gas Well Sites	1.92	0.53	2.03	0.56	3.28	0.91
Low Production Oil Well Sites (GOR < 300)	0.73	0.20	0.77	0.21	1.25	0.35
Low Production Oil Well Sites (GOR > 300)	1.05	0.29	1.11	0.31	1.8	0.50
Stepped Monitoring						
Gas Well Sites	2.66	0.74	2.68	0.75	4.14	1.15
Oil Well Sites (GOR < 300)	0.93	0.26	0.93	0.26	1.44	0.40
Oil Well Sites (GOR > 300)	1.37	0.38	1.38	0.38	2.13	0.59
Low Production Gas Well Sites	2.16	0.60	2.18	0.61	3.37	0.94
Low Production Oil Well Sites (GOR < 300)	0.82	0.23	0.83	0.23	1.28	0.36
Low Production Oil Well Sites (GOR > 300)	1.18	0.33	1.19	0.33	1.84	0.51
Semiannual Monitoring						
Gas Well Sites	3.55	0.99	3.24	0.90	4.46	1.24
Oil Well Sites (GOR < 300)	1.23	0.34	1.13	0.31	1.55	0.43
Oil Well Sites (GOR > 300)	1.82	0.51	1.67	0.46	2.29	0.64
Low Production Gas Well Sites	2.88	0.80	2.63	0.73	3.62	1.01
Low Production Oil Well Sites (GOR < 300)	1.10	0.31	1.00	0.28	1.38	0.38
Low Production Oil Well Sites (GOR > 300)	1.58	0.44	1.44	0.40	1.98	0.55

a. Assumes baseline emissions shown in Tables 2-5 and 2-8 and percent reduction shown in Table 2-21.

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Table 2-~~15b~~16b. Model Plant Emission Reductions for OGI and EPA Method 21 Monitoring and Repair – Biennial Monitoring

Affected Facility	OGI Monitoring (tpy)		Method 21 10,000 ppm (tpy)[a]		Method 21 500 ppm (tpy)[a]	
	Methane	VOC	Methane	VOC	Methane	VOC
Biennial Monitoring						
Low Production Gas Well Sites	1.44	0.40	1.44	0.40	2.93	0.81
Low Production Oil Well Sites (GOR < 300)	0.55	0.15	0.55	0.15	1.12	0.31
Low Production Oil Well Sites (GOR > 300)	0.79	0.22	0.79	0.22	1.60	0.45

Table 2-16c. Model Plant Emission Reductions for OGI and EPA Method 21 Monitoring and Repair – Compressor Station

Affected Facility	OGI Monitoring (tpy)		Method 21 10,000 ppm (tpy)[a]		Method 21 500 ppm (tpy)[a]	
	Methane	VOC	Methane	VOC	Methane	VOC
Annual Monitoring						
Gathering & Boosting	14.1	3.91	14.8	4.12	24.0	6.67
Transmission	16.2	0.45	17.0	0.47	27.6	0.76
Storage	57.0	1.58	60.1	1.66	97.3	2.69
Semiannual Monitoring						
Gathering & Boosting	21.1	5.86	19.3	5.35	26.5	7.37
Transmission	24.2	0.67	22.1	0.61	30.5	0.84
Storage	85.5	2.37	78.1	2.16	107.4	2.97
Quarterly Monitoring						
Gathering & Boosting	28.1	7.81	23.7	6.58	29.0	8.06
Transmission	32.3	0.89	27.2	0.75	33.0	0.92
Storage	114.0	3.15	96.0	2.66	117.5	3.25

a. Assumes baseline emissions shown in Tables 2-5 and 2-8 and percent reduction shown in Table 2-21.

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2.4.2.3 Cost Impacts of Method 21-Based Program

Costs for preparing a Method 21 fugitive emission monitoring and repair plan for a company defined area (*i.e.,* field or district) were estimated using hourly estimates for each of the monitoring and repair plan elements. The costs are based on the following assumptions (costs are presented in 2016$):

- Labor cost for each of the monitoring plan elements, such as reading the rule, was estimated to be $61.21 per hour.
- Reading of the rule and instructions would take 1 person 4 hours to complete at a cost of $245.
- Development of a fugitive emission monitoring plan would take 2.5 people a total of 60 hours to complete at a cost of $3,672.
- Initial activities planning are estimated to take 2 people a total of 8 hours per person for each monitoring event. ~~Cost for~~Annual cost for biennial monitoring was estimated to be $490, annual monitoring was estimated to be $979, semiannual monitoring was estimated to be $1,959, and stepped monitoring $1,224 for well sites. For compressor stations, the initial activities planning cost are estimated at $1,959 for all monitoring frequencies.
- Notification of compliance status was estimated to take 1 person 1 hour to complete at a cost of $61.21 per well site and compressor stations. We estimated that 22 well sites within each company-defined area for a total of $1,347 for well sites. We estimated 7 gathering and boosting stations per company for a total of $428 and 1 transmission or storage station per notification for a total of $61.21 per transmission and storage station.
- It was estimated that a Method 21 monitoring instrument costs $10,800 instrument and the data collection system costs $14,500.

Costs for implementing a fugitive emission monitoring plan for a company defined area (*i.e.,* field or district) were estimated for each of the monitoring and repair elements. The costs are based on the following assumptions:

- Subsequent activities planning are estimated to take 2 people a total of 8 hours per person to complete at a cost of $979 per monitoring event at well sites. For oil and natural gas production well sites, this cost was divided among the total number of well sites owned in a company defined area, which was assumed to be 22. The cost per well site was estimated to be $45 per monitoring event. The subsequent activities planning are estimated to take 2 people a total of 12 hours per person to complete at a cost of $1,469 per monitoring event for compressor stations.

- The Method 21 monitoring survey was estimated to take 2 people a total of 8 hours per person to complete at a cost of $979 for each monitoring event at a well site. For gathering and boosting stations, it was estimated to take 2 people a total of 16 hours per person to complete a Method 21 survey at a cost of $1,959 for each monitoring event. For transmission stations, it was estimated to take 2 people a total of 23 hours per person to complete a Method 21 survey at a cost of $2,815 per monitoring event. For storage stations, it was estimated to take 2 people a total of 42 hours to complete a Method 21 survey at a cost of $5,141.[34]
- Annual repair costs were estimated to be $316 per monitoring event for well sites, $3,638 per monitoring event for gathering and boosting stations, $3,559 per monitoring event for transmission stations, and $7,355 per monitoring event for storage stations. These costs were estimated assuming that 1.18 percent of the components are identified with fugitive emissions[35] during monitoring and 75 percent are repaired online and 25 percent are repaired offline.
- Costs to resurvey the repaired components that could not be fixed during the initial survey using a Method 21 device was estimated using a resurvey time of 5 minutes per leak at a cost of $61.21 per hour. This assumes the company is able to perform the resurvey without retaining contractors.
- Preparation of annual reports was estimated to take 1 person a total of 4 hours to complete at a cost of $245.

The initial setup cost or capital cost for oil and natural gas well sites was calculated by summing up the costs for reading the rule, development of fugitive emissions monitoring plan, initial activities planning, and notification of initial compliance status. The total capital cost of these activities at well sites was calculated to be $31,~~543~~053 per company defined area for biennial monitoring, $31,543 for annual monitoring, $31,788 for the stepped monitoring, and $32,522 for semiannual monitoring. Assuming that each company owns and operates 22 well sites within a company defined area[36], the capital cost per well site was estimated to be $1,412 for biennial monitoring, $1,434 for annual monitoring, $1,445 for stepped monitoring and $1,478 for semiannual monitoring. For gathering and boosting compressor stations the capital cost for reading the rule, development of fugitive emissions monitoring plan, and initial activities

[34] Costs for contractor based OGI monitoring obtained from the Carbon Limits report.

[35] The assumption of 1.18% leak rate for OGI monitoring was obtained from Table 5 of the Uniform Standards memorandum. The 1.18% value is the baseline leak frequency for valves in gas/vapor service. None of the other baseline frequencies in this table were used because the equipment are in liquid service (*e.g.*, pumps LL, valve LL, agitators LL). There is no information on the number of leaks located at uncontrolled facilities, only average percentages of the total number of components at a facility. Therefore, our methodology was to use the 1.18% leak frequency value from the Uniform Standards memorandum and apply that value to the total number of components at the oil and natural gas model plant. (Uniform Standards Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180).

[36] The number of well sites owned and operated by companies was calculated using data from the Fort Worth study.

planning notification of initial compliance status was calculated to be $31,237, which was assumed to be shared between 7 gathering and boosting stations within the company defined area. These stations are estimated to be approximately 70 miles apart. Therefore, within a 210 mile radius of a central location, the capital cost of each of these stations was estimated to be $4,462. For transmission and storage stations, the capital cost per facility was calculated to be $31,237.

For all oil and natural gas segments, the annual cost includes subsequent activities planning, Method 21 survey, cost of repair of fugitive emissions found, resurvey of repaired components, preparation and submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. For our analysis the EPA calculated the annual cost for annual, stepped, and semiannual Method 21 surveys at well sites, and annual, semiannual, and quarterly Method 21 surveys at compressor stations.

We use the same two methods (single pollutant and multipollutant) discussed in section 2.4.1.3 for the Method 21 program. Based on estimated emissions reductions and the estimated cost for implementing a Method 21 fugitive emissions monitoring and repair program at the affected facilities, the EPA calculated a cost of control for methane and VOC for the various options for oil and natural gas production well sites, gathering and boosting, and transmission and storage compressor stations. The EPA then calculated the cost of control of well sites and compressor stations using the weighted average cost of control for all well sites and all compressor stations (*i.e.,* gathering and boosting, transmission and storage). Tables 2-~~16, 2-~~17, 2-18, 2-19, 2-20, and 2-~~19~~21 present a summary of the cost of control for methane and VOC for the various Method 21 monitoring frequency options (*i.e.,* biennial, annual, semiannual, stepped, and quarterly, respectively).

2.4.2.4 Secondary Impacts

No secondary gaseous pollutant emissions or wastewater are generated during the monitoring and repair of fugitive emissions components. There are some emissions that would be generated by the Method 21 monitoring contractors with respect to driving to and from the site for the fugitive emissions survey, as discussed in section 2.4.1.4 for OGI. We assume the same mobile emissions from the Method 21 program.

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Table 2-~~16~~17. Summary of the Model Plant Cost of Control for Biennial Method 21 Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	500 ppm				10,000 ppm			
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Single Pollutant Approach								
Low Production Well Site Program	$791	$2,847	$593	$2,134	$1,609	$5,789	$1,411	$5,076
Multipollutant Approach								
Low Production Well Site Program	$396	$1,423	$297	$1,067	$805	$2,894	$705	$2,538

a. The weighted average for the segments were calculated using the 2014 activity counts of 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), and 1,222 low production oil well sites (GOR>300).
b. Recovery credits for oil and natural gas production well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42/Mcf.

Table 2-18. Summary of the Model Plant Cost of Control for Annual Method 21 Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	500 ppm				10,000 ppm			
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Single Pollutant Approach								
Non-Low Production Well Site Program	$809	$2,909	$610	$2,196	$1,309	$4,708	$1,110	$3,995
Low Production Well Site Program	$1,123	$4,040	$925	$3,327	$1,818	$6,539	$1,619	$5,826
Compressor Station Program	$376	$1,632	$216	$935	$609	$2,642	$448	$1,945
Multipollutant Approach								
Non-Low Production Well Site Program	$404	$1,454	$305	$1,098	$654	$2,354	$555	$1,997
Low Production Well Site Program	$562	$2,020	$462	$1,664	$909	$3,269	$810	$2,913
Compressor Station Program	$188	$816	$108	$468	$305	$1,321	$224	$972

a. The weighted average for the segments were calculated using the 2014 activity counts of 2,001 non-low production gas well sites, 1,848 non-low production oil well sites (GOR<300), 9,190 non-low production oil well sites (GOR>300), 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), 1,222 low production oil well sites (GOR>300), 212 G&B stations, 36 transmission stations, and 2 storage facilities.

b. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42/ Mcf.

Note: Transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

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Table 2-~~17~~19. Summary of the Model Plant Cost of Control for Semiannual Method 21 Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	500 ppm				10,000 ppm			
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Single Pollutant Approach								
Non-Low Production Well Site Program	$1,275	$4,588	$1,077	$3,875	$1,755	$6,313	$1,557	$5,600
Low Production Well Site Program	$1,771	$6,372	$1,573	$5,659	$2,437	$8,768	$2,239	$8,055
Compressor Station Program	$568	$2,465	$408	$1,768	$782	$3,392	$621	$2,695
Multipollutant Approach								
Non-Low Production Well Site Program	$638	$2,294	$539	$1,937	$877	$3,156	$778	$2,800
Low Production Well Site Program	$886	$3,186	$787	$2,830	$1,219	$4,384	$1,120	$4,027
Compressor Station Program	$284	$1,233	$204	$884	$391	$1,696	$311	$1,348

a. The weighted average for the segments were calculated using the 2014 activity counts of 2,001 non-low production gas well sites, 1,848 non-low production oil well sites (GOR<300), 9,190 non-low production oil well sites (GOR>300), 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), 1,222 low production oil well sites (GOR>300), 212 G&B stations, 36 transmission stations, and 2 storage facilities.

b. Recovery credits for oil and natural gas production well sites and gathering and boosting stations were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42/ Mcf.

Note: Transmission and storage facilities do not own the natural gas; therefore revenues from reducing the amount of natural gas as the result of equipment leaks was not estimated for these segments.

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Table 2-~~18~~20. Summary of the Model Plant Cost of Control for Stepped Method 21 Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	500 ppm				10,000 ppm			
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Single Pollutant Approach								
Non-Low Production Well Site Program	$965	$3,471	$767	$2,758	$1,491	$5,363	$1,293	$4,650
Low Production Well Site Program	$1,340	$4,820	$1,142	$4,107	$2,071	$7,449	$1,872	$6,736
Multipollutant Approach								
Non-Low Production Well Site Program	$482	$1,735	$383	$1,379	$745	$2,681	$646	$2,325
Low Production Well Site Program	$670	$2,410	$571	$2,054	$1,035	$3,724	$936	$3,368

a. The weighted average for the segments were calculated using the 2014 activity counts of 2,001 non-low production gas well sites, 1,848 non-low production oil well sites (GOR<300), 9,190 non-low production oil well sites (GOR>300), 409 low production gas well sites, 2,171 low production oil well sites (GOR<300), and 1,222 low production oil well sites (GOR>300).
b. Recovery credits for oil and natural gas production well sites were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition, and the value of the natural gas recovered as $3.42/Mcf.

Table 2-~~19~~21. Summary of the Model Plant Cost of Control for Quarterly Method 21 Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)		Cost of Control (without savings) ($/ton)		Cost of Control (with saving)[b] ($/ton)	
	500 ppm				10,000 ppm			
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Single Pollutant Approach								
Compressor Station Program	$935	$4,057	$775	$3,360	$1,145	$4,965	$984	$4,269
Multipollutant Approach								
Compressor Station Program	$468	$2,028	$387	$1,680	$573	$2,483	$492	$2,134

a. The weighted average for the segments were calculated using the 2014 activity counts of 212 G&B stations, 36 transmission stations, and 2 storage facilities.
b. Recovery credits were calculated assuming natural gas reductions based methane reductions, methane as 82.9% of natural gas composition for gathering and boosting and the value of the natural gas recovered as $3.42/Mcf.

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2.5 Regulatory Options

As discussed in section 2.4, we continue to conclude that a fugitive emissions monitoring and repair program using OGI or Method 21 is the most viable method for reducing fugitive emissions at well sites and compressor stations. Therefore, we evaluated the following regulatory options to evaluate both monitoring techniques:

- Regulatory Option 1: The implementation of a fugitive emissions monitoring and repair program using OGI as the detection method. The following sub-options were evaluated for different monitoring frequencies, as shown below.
    - 1a. Monitoring on an annual frequency at well sites and compressor stations.
    - 1b. Monitoring on a semiannual frequency for 2 years, followed by annual monitoring thereafter at well sites.
    - 1c. Monitoring on a semiannual frequency at well sites and compressor stations.
    - 1d. Monitoring on a quarterly frequency at compressor stations.
    - 1e. Monitoring on a biennial frequency at low production well sites.
- Regulatory Option 2: The implementation of a fugitive emissions monitoring and repair program using Method 21 as the detection method, with a repair threshold of 500 ppm. The following sub-options were evaluated for different monitoring frequencies, as shown below.
    - 2a. Monitoring on an annual frequency at well sites and compressor stations.
    - 2b. Monitoring on a semiannual frequency for 2 years, followed by annual monitoring thereafter at well sites.
    - 2c. Monitoring on a semiannual frequency at well sites and compressor stations.
    - 2d. Monitoring on a quarterly frequency at compressor stations.
    - 2e. Monitoring on a biennial frequency at low production well sites.
- Regulatory Option 3: The implementation of a fugitive emissions monitoring and repair program using Method 21 as the detection method, with a repair threshold of 10,000 ppm. The following sub-options were evaluated for different monitoring frequencies, as shown below.
    - 3a. Monitoring on an annual frequency at well sites and compressor stations.
    - 3b. Monitoring on a semiannual frequency for 2 years, followed by annual monitoring thereafter at well sites.
    - 3c. Monitoring on a semiannual frequency at well sites and compressor stations.

- 3d. Monitoring on a quarterly frequency at compressor stations.
- 3e. Monitoring on a biennial frequency at low production well sites.

2.5.1 Evaluation of Regulatory Options for Fugitive Emissions

As noted above, the EPA calculated a weighted average cost of control for non-low production and low production well sites (which includes oil wells, oil wells with associated gas, and natural gas production well sites) and compressor stations (which includes gathering and boosting stations, transmission stations and storage facilities). For ease of review the EPA has summarized the cost of control for the options for well sites and compressor stations in Table 2-~~20~~22.

2.5.1.1 Option 1 – OGI Monitoring

Non-Low Production Well Sites. For non-low production well sites, we have three sub-options based on the frequency of OGI monitoring conducted, Options 1a, 1b, and 1c. Under the single pollutant approach for the annual monitoring frequency (Option 1a), if all costs are assigned to methane and zero to VOC reductions, the cost is $972 per ton of methane reduced, and $773 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,495 per ton of VOC reduced, and $2,782 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $1,748 per ton VOC reduced, and $1,391 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $486 per ton methane reduced, and $387 per ton if natural gas savings are considered.

Under the single pollutant approach for the stepped monitoring frequency (Option 1b), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,032 per ton of methane reduced, and $834 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,713 per ton of VOC reduced, and $3,000 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual to annual monitoring is $1,857 per ton VOC reduced, and $1,500 per ton if natural gas savings are considered. The control cost for methane based on semiannual to annual monitoring under the multipollutant approach is $516 per ton methane reduced, and $417 per ton if natural gas savings are considered.

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Finally, for semiannual monitoring (Option 1c) of non-low production well sites, under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,153 per ton of methane reduced, and $955 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,149 per ton of VOC reduced, and $3,436 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $2,075 per ton VOC reduced, and $1,718 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $577 per ton methane reduced, and $478 per ton if natural gas savings are considered.

Low Production Well Sites. Similarly for low production well sites, under the single pollutant approach for the annual monitoring frequency (Option 1a), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,360 per ton of methane reduced, and $1,140 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,893 per ton of VOC reduced, and $4,102 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $2,446 per ton VOC reduced, and $2,051 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $680 per ton methane reduced, and $570 per ton if natural gas savings are considered.

Under the single pollutant approach for the stepped monitoring frequency (Option 1b), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,445 per ton of methane reduced, and $1,247 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $5,200 per ton of VOC reduced, and $4,487 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on stepped monitoring is $2,600 per ton VOC reduced, and $2,243 per ton if natural gas savings are considered. The control cost for methane based on semiannual to annual monitoring under the multipollutant approach is $723 per ton methane reduced, and $624 per ton if natural gas savings are considered.

~~Finally for~~For semiannual monitoring (Option 1c), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,616 per ton of methane reduced, and $1,396 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $5,814 per ton of VOC reduced, and $5,023 per ton of VOC reduced if savings

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of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $2,907 per ton VOC reduced, and $2,512 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $808 per ton methane reduced, and $698 per ton if natural gas savings are considered.

Finally for the biennial monitoring (Option 1e), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,104 per ton of methane reduced, and $906 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,972 per ton of VOC reduced, and $3,259 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on biennial monitoring is $1,986 per ton VOC reduced, and $1,629 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $552 per ton methane reduced, and $453 per ton if natural gas savings are considered.

Wellhead Only Well Sites. For wellhead only well sites, under the single pollutant approach for the annual monitoring frequency (Option 1a), if all costs are assigned to methane and zero to VOC reductions, the cost is $6,349 per ton of methane reduced, and $5,064 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $22,840 per ton of VOC reduced, and $18,217 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $11,420 per ton VOC reduced, and $9,109 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $3,174 per ton methane reduced, and $2,532 per ton if natural gas savings are considered. Given these high cost for control, we did not evaluate more frequent monitoring at these wellhead only well sites.

Compressor Stations. For compressor stations, under the single pollutant approach for the annual monitoring frequency (Option 1a), if all costs are assigned to methane and zero to VOC reductions, the cost is $557 per ton of methane reduced, and $396 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $2,414 per ton of VOC reduced, and $1,717 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $1,207 per ton VOC reduced, and $859 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $278 per ton methane reduced, and $198 per ton if natural gas savings are considered.

Under the single pollutant approach for semiannual monitoring (Option 1c), if all costs are assigned to methane and zero to VOC reductions, the cost is $652 per ton of methane reduced, and $491 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $2,827 per ton of VOC reduced, and $2,130 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $1,413 per ton VOC reduced, and $1,065 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $326 per ton methane reduced, and $246 per ton if natural gas savings are considered.

Finally, for quarterly monitoring (Option 1d), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $910 per ton of methane reduced, and $749 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,946 per ton of VOC reduced, and $3,250 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on quarterly monitoring is $1,973 per ton VOC reduced, and $1,625 per ton if natural gas savings are considered. The control cost for methane based on quarterly monitoring under the multipollutant approach is $455 per ton methane reduced, and $375 per ton if natural gas savings are considered.

Because the gas handled by transmission and storage facilities is not typically owned by these facilities, we do not consider the value of the gas saved as an offset to the cost. However, for gathering and boosting stations, the gas savings could be considered. Therefore, we calculated the cost of control for compressor stations considering the gas savings contributed by gathering and boosting stations. This cost savings is reflected in the cost presented above and summarized in Table 2-~~20~~22.

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Table 2-~~20~~22. Summary of the Cost of Control for the OGI Monitoring Options

Option	Cost of Control (without gas savings)				Cost of Control (with gas savings)			
	Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)		Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Non-Low Production Well Sites								
1a - Annual	$979	$3,523	$490	$1,761	$781	$2,810	$391	$1,405
1b - Stepped	$1,041	$3,744	$520	$1,872	$842	$3,031	$421	$1,515
1c - Semiannual	$1,164	$4,186	$582	$2,093	$965	$3,473	$483	$1,736
Low Production Well Sites								
1a - Annual	$1,360	$4,893	$680	$2,446	$1,140	$4,102	$570	$2,051
1b - Stepped	$1,445	$5,200	$723	$2,600	$1,247	$4,487	$624	$2,243
1c - Semiannual	$1,616	$5,814	$808	$2,907	$1,396	$5,023	$698	$2,512
1c – Biennial	$1,104	$3,972	$552	$1,986	$906	$3,259	$453	$1,629
Wellhead Only Well Sites								
1a - Annual	$6,349	$22,840	$3,174	$11,420	$5,064	$18,217	$2,532	$9,109
Compressor Stations								
1a - Annual	$557	$2,414	$278	$1,207	$396	$1,717	$198	$859
1b - Semiannual	$652	$2,827	$326	$1,413	$491	$2,130	$246	$1,065
1d - Quarterly	$910	$3,946	$455	$1,973	$749	$3,250	$375	$1,625

2.5.1.2 Option 2 – Method 21 Monitoring with a 500 ppm Repair Threshold

Non-Low Production Well Sites. The same three sub-options used in section 2.5.1.1 were evaluated for Method 21 monitoring with a 500 ppm repair threshold, Options ~~1a, 1b~~2a, 2b, and ~~1c~~2c. Under the single pollutant approach for the annual monitoring frequency (Option ~~1a~~2a), if all costs are assigned to methane and zero to VOC reductions, the cost is $809 per ton of methane reduced, and $610 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $2,909 per ton of VOC reduced, and $2,196 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $1,454 per ton VOC reduced, and $1,098 per ton if natural gas savings are

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considered. The control cost for methane based on annual monitoring under the multipollutant approach is $404 per ton methane reduced, and $305 per ton if natural gas savings are considered.

Under the single pollutant approach for the stepped monitoring frequency (Option ~~1b~~2b), if all costs are assigned to methane and zero to VOC reductions, the cost is $965 per ton of methane reduced, and $767 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,471 per ton of VOC reduced, and $2,758 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual to annual monitoring is $1,735 per ton VOC reduced, and $1,379 per ton if natural gas savings are considered. The control cost for methane based on semiannual to annual monitoring under the multipollutant approach is $482 per ton methane reduced, and $383 per ton if natural gas savings are considered.

Finally, for semiannual monitoring (Option ~~1c~~2c) of non-low production well sites, under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,275 per ton of methane reduced, and $1,077 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,588 per ton of VOC reduced, and $3,875 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $2,294 per ton VOC reduced, and $1,937 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $638 per ton methane reduced, and $539 per ton if natural gas savings are considered.

Low Production Well Sites. Similarly for low production well sites, under the single pollutant approach for the annual monitoring frequency (Option ~~1a~~2a), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,123 per ton of methane reduced, and $925 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,040 per ton of VOC reduced, and $3,327 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $2,020 per ton VOC reduced, and $1,664 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $562 per ton methane reduced, and $462 per ton if natural gas savings are considered.

Under the single pollutant approach for the stepped monitoring frequency (Option ~~1b~~2b), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,340 per ton of methane reduced,

and $1,142 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,820 per ton of VOC reduced, and $4,107 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on stepped monitoring is $2,410 per ton VOC reduced, and $2,054 per ton if natural gas savings are considered. The control cost for methane based on semiannual to annual monitoring under the multipollutant approach is $670 per ton methane reduced, and $571 per ton if natural gas savings are considered.

~~Finally for~~For semiannual monitoring (Option ~~1e~~2e), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,771 per ton of methane reduced, and $1,573 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $6,372 per ton of VOC reduced, and $5,659 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $3,186 per ton VOC reduced, and $2,830 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $886 per ton methane reduced, and $787 per ton if natural gas savings are considered.

~~*Compressor Stations.*~~ Finally for the biennial monitoring (Option 2e), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $791 per ton of methane reduced, and $593 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $2,847 per ton of VOC reduced, and $2,134 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on biennial monitoring is $1,423 per ton VOC reduced, and $1,067 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $396 per ton methane reduced, and $297 per ton if natural gas savings are considered.

Compressor Stations. For compressor stations, under the single pollutant approach for the annual monitoring frequency (Option ~~1a~~2a), if all costs are assigned to methane and zero to VOC reductions, the cost is $338 per ton of methane reduced, and $181 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $1,493 per ton of VOC reduced, and $798 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $746 per ton VOC

reduced, and $399 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $169 per ton methane reduced, and $90 per ton if natural gas savings are considered.

Under the single pollutant approach for semiannual monitoring (Option ~~1e~~2c), if all costs are assigned to methane and zero to VOC reductions, the cost is $519 per ton of methane reduced, and $362 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $2,292 per ton of VOC reduced, and $1,597 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $1,146 per ton VOC reduced, and $799 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $260 per ton methane reduced, and $181 per ton if natural gas savings are considered.

Finally for quarterly monitoring (Option ~~1d~~2d), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $864 per ton of methane reduced, and $706 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,813 per ton of VOC reduced, and $3,118 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on quarterly monitoring is $1,907 per ton VOC reduced, and $1,559 per ton if natural gas savings are considered. The control cost for methane based on quarterly monitoring under the multipollutant approach is $432 per ton methane reduced, and $353 per ton if natural gas savings are considered.

Because the gas handled by transmission and storage facilities is not typically owned by these facilities, we do not consider the value of the gas saved as an offset to the cost. However, for gathering and boosting stations, the gas savings could be considered. Therefore, we calculated the cost of control for compressor stations considering the gas savings contributed by gathering and boosting stations. This cost savings is reflected in the cost presented above and summarized in Table 2-~~21~~23.

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Table 2-~~21~~23. Summary of the Cost of Control for the Method 21 Monitoring Options with a Repair Threshold of 500 ppm

Option	Cost of Control (without gas savings)				Cost of Control (with gas savings)			
	Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)		Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Non-Low Production Well Sites								
~~1a~~2a - Annual	$809	$2,909	$404	$1,453	$610	$2,196	$305	$1,096
~~1b~~2b - Stepped	$965	$3,471	$482	$1,735	$767	$2,758	$383	$1,379
~~1c~~2c - Semiannual	$1,275	$4,588	$638	$2,294	$1,077	$3,875	$539	$1,937
Low Production Well Sites								
~~1a~~2a - Annual	$1,123	$4,040	$562	$2,020	$925	$3,327	$462	$1,664
~~1b~~2b - Stepped	$1,340	$4,820	$670	$2,410	$1,142	$4,107	$571	$2,054
~~1c~~2c - Semiannual	$1,771	$6,372	$886	$3,186	$1,573	$5,659	$787	$2,830
2e – Biennial	$791	$2,847	$396	$1,423	$593	$2,134	$297	$1,067
Compressor Stations								
~~1a~~2a - Annual	$338	$1,493	$169	$746	$181	$798	$90	$399
~~1b~~2b - Semiannual	$519	$2,292	$260	$1,146	$362	$1,597	$181	$799
~~1d~~2d - Quarterly	$864	$3,813	$432	$1,907	$706	$3,118	$353	$1,559

2.5.1.3 Option 3 – Method 21 Monitoring with a 10,000 ppm Repair Threshold

Non-Low Production Well Sites. The same three sub-options used in sections 2.5.1.1 and 2.5.1.2 were evaluated for Method 21 monitoring with a 10,000 ppm repair threshold, Options ~~1a, 1b~~3a, 3b, and ~~1c~~3c. Under the single pollutant approach for the annual monitoring frequency (Option ~~1a~~3a), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,309 per ton of methane reduced, and $1,110 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,708 per ton of VOC reduced, and $3,995 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC

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based on annual monitoring is $2,354 per ton VOC reduced, and $1,997 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $654 per ton methane reduced, and $555 per ton if natural gas savings are considered.

Under the single pollutant approach for the stepped monitoring frequency (Option ~~1b~~3b), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,491 per ton of methane reduced, and $1,293 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $5,363 per ton of VOC reduced, and $4,650 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual to annual monitoring is $2,681 per ton VOC reduced, and $2,325 per ton if natural gas savings are considered. The control cost for methane based on semiannual to annual monitoring under the multipollutant approach is $745 per ton methane reduced, and $646 per ton if natural gas savings are considered.

Finally, for semiannual monitoring (Option ~~1c~~3c) of non-low production well sites, under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,755 per ton of methane reduced, and $1,557 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $6,313 per ton of VOC reduced, and $5,600 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $3,156 per ton VOC reduced, and $2,800 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $877 per ton methane reduced, and $778 per ton if natural gas savings are considered.

Low Production Well Sites. Similarly for low production well sites, under the single pollutant approach for the annual monitoring frequency (Option ~~1a~~3a), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,818 per ton of methane reduced, and $1,619 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $6,539 per ton of VOC reduced, and $5,826 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual monitoring is $3,269 per ton VOC reduced, and $2,913 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $909 per ton methane reduced, and $810 per ton if natural gas savings are considered.

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Under the single pollutant approach for the stepped monitoring frequency (Option ~~1b~~3b), if all costs are assigned to methane and zero to VOC reductions, the cost is $2,071 per ton of methane reduced, and $1,872 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $7,449 per ton of VOC reduced, and $6,736 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on stepped monitoring is $3,724 per ton VOC reduced, and $3,368 per ton if natural gas savings are considered. The control cost for methane based on semiannual to annual monitoring under the multipollutant approach is $1,035 per ton methane reduced, and $936 per ton if natural gas savings are considered.

Finally for semiannual monitoring (Option ~~1c~~3c), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $2,437 per ton of methane reduced, and $2,239 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $8,768 per ton of VOC reduced, and $8,055 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $4,384 per ton VOC reduced, and $4,027 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $1,219 per ton methane reduced, and $1,120 per ton if natural gas savings are considered.

Finally for the biennial monitoring (Option 3e), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,609 per ton of methane reduced, and $1,411 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $5,789 per ton of VOC reduced, and $5,076 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on biennial monitoring is $2,894 per ton VOC reduced, and $2,538 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $805 per ton methane reduced, and $705 per ton if natural gas savings are considered.

Compressor Stations. ~~*Compressor Stations.*~~ For compressor stations, under the single pollutant approach for the annual monitoring frequency (Option ~~1a~~3a), if all costs are assigned to methane and zero to VOC reductions, the cost is $547 per ton of methane reduced, and $390 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $2,416 per ton of VOC reduced, and $1,721 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on annual

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monitoring is $1,208 per ton VOC reduced, and $860 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multipollutant approach is $274 per ton methane reduced, and $195 per ton if natural gas savings are considered.

Under the single pollutant approach for semiannual monitoring (Option ~~1e~~3c), if all costs are assigned to methane and zero to VOC reductions, the cost is $714 per ton of methane reduced, and $557 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,154 per ton of VOC reduced, and $2,459 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on semiannual monitoring is $1,577 per ton VOC reduced, and $1,229 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multipollutant approach is $357 per ton methane reduced, and $278 per ton if natural gas savings are considered.

Finally for quarterly monitoring (Option ~~1d~~3d), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,057 per ton of methane reduced, and $900 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,668 per ton of VOC reduced, and $3,973 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multipollutant approach, the control cost for VOC based on quarterly monitoring is $2,334 per ton VOC reduced, and $1,986 per ton if natural gas savings are considered. The control cost for methane based on quarterly monitoring under the multipollutant approach is $529 per ton methane reduced, and $450 per ton if natural gas savings are considered.

Because the gas handled by transmission and storage facilities is not typically owned by these facilities, we do not consider the value of the gas saved as an offset to the cost. However, for gathering and boosting stations, the gas savings could be considered. Therefore, we calculated the cost of control for compressor stations considering the gas savings contributed by gathering and boosting stations. This cost savings is reflected in the cost presented above and summarized in Table 2-~~22~~24.

Table 2-~~22~~24. Summary of the Cost of Control for the Method 21 Monitoring Options with a Repair Threshold of 10,000 ppm

Option	Cost of Control (without gas savings)				Cost of Control (with gas savings)			
	Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)		Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Non-Low Production Well Sites								
~~1a~~3a - Annual	$1,309	$4,708	$654	$2,354	$1,110	$3,995	$555	$1,997
~~1b~~3b - Stepped	$1,491	$5,363	$745	$2,681	$1,293	$4,650	$646	$2,325
~~1c~~3c - Semiannual	$1,755	$6,313	$877	$3,156	$1,557	$5,600	$778	$2,800
Low Production Well Sites								
~~1a~~3a - Annual	$1,818	$6,539	$909	$3,269	$1,619	$5,826	$810	$2,913
~~1b~~3b - Stepped	$2,071	$7,449	$1,035	$3,724	$1,872	$6,736	$936	$3,368
~~1c~~3c - Semiannual	$2,437	$8,768	$1,219	$4,384	$2,239	$8,055	$1,120	$4,027
3e – Biennial	$1,609	$5,789	$805	$2,894	$1,411	$5,076	$705	$2,538
Compressor Stations								
~~1a~~3a - Annual	$547	$2,416	$274	$1,208	$390	$1,721	$195	$860
~~1b~~3b - Semiannual	$714	$3,154	$357	$1,577	$557	$2,459	$278	$1,229
~~1d~~3d - Quarterly	$1,057	$4,668	$529	$2,334	$900	$3,973	$450	$1,986

2.6 Sensitivity Analysis

2.6.1 Fugitive Emissions Estimation of Percent Leaking

The EPA performed a sensitivity analysis on the estimates of components identified with fugitive emissions, herein referred to as the "percent leaking". This value is calculated by dividing the number of components identified with fugitive emissions by the total number of components monitored. In 2016, the EPA estimated that 1.18% of the fugitive emissions components would be identified as having fugitive

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emissions.[37] This value directly affects the repair costs that are estimated for the fugitive emissions requirements. For each of the model plants in this analysis, the 1.18% equates to 4 repairs at non-low production and low production well sites, 46 repairs at gathering and boosting stations, 45 repairs at transmission compressor stations, and 93 repairs at storage compressor stations.

The EPA received data from the American Petroleum Institute (API),[38] GPA Midstream (GPA),[39] and Target Emission Services (Target)[40] that includes the percent leaking based on fugitive emissions monitoring at well sites, gathering and boosting stations, and transmission compressor stations. The majority of this data was based on the use of OGI, however, there was some limited information from gathering and boosting stations on the use of Method 21. The EPA evaluated this data, though direct comparison with the EPA's model plant analysis was difficult due to several uncertainties which are discussed in detail in the memorandums in the docket.[41] It is important to note that since we utilize the average emissions factors, as discussed in section 2.3.5, the emissions are not affected by any changes in the percent leaking values used. Therefore, the only effect the percent leaking has on the cost of control is due to a change in the cost of repairs.

The information submitted by API was specific to initial monitoring at 4,117 well sites located throughout the United States in a variety of different basins.[42] The data included 1,521 single-wellhead gas sites, 755 multi-wellhead gas sites, 1,164 single-wellhead oil sites, and 677 multi-wellhead oil sites. The data represented the first monitoring survey for each site, and all monitoring surveys were conducted using OGI. API included an evaluation of the percent leaking for these well sites and concluded that the average initial percent leaking for all well sites was 0.4% of the components surveyed. The EPA performed a separate analysis of the raw data, and concluded the average initial percent leaking for that

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[37] The assumption of 1.18% leak rate for OGI monitoring was obtained from Table 5 of the Uniform Standards memorandum. The 1.18% value is the baseline leak frequency for valves in gas/vapor service. None of the other baseline frequencies in this table were used because the equipment are in liquid service (*e.g.*, pumps LL, valve LL, agitators LL). There is no information on the number of leaks located at uncontrolled facilities, only average percentages of the total number of components at a facility. Therefore, our methodology was to use the 1.18% leak frequency value from the Uniform Standards memorandum and apply that value to the total number of components at the oil and natural gas model plant. (Uniform Standards Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA-HQ-OAR-2002-0037-0180).

[38] See memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 17, 2018.

[39] See memorandum *EPA Analysis of Compressor Station Fugitive Emissions Monitoring Data Provided by GPA Midstream* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 17, 2018.

[40] See memorandum *NSPS OOOOa Monitoring Case Study Presentation by Terence Trefiak with Target Emission Services* located at Docket ID No. EPA-HQ-OAR-2017-0483. March 13, 2018.

[41] See memorandums in footnotes 19, 20, and 21.

[42] The data represented well sites in Alaska, Arkansas, Colorado, Louisiana, Montana, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, Utah, West Virginia, and Wyoming.

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data set was 0.54%. Despite uncertainties associated with the data,[43] the EPA performed an analysis of the cost of control using both the EPA's estimated value of 1.18% and the estimated 0.54% from EPA's evaluation of API's data. Table 2-~~23~~25 summarizes the results of this analysis.

Table 2-~~23~~25. Comparison of Cost of Control Options at Well Sites (without cost savings)

Option	Cost of Control (1.18% leaking)				Cost of Control (0.54% leaking)			
	Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)		Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Non-Low Production Well Sites								
1a - Annual	$979	$3,744	$490	$1,761	$961	$3,459	$481	$1,729
1b - Stepped	$1,041	$3,523	$520	$1,872	$1,021	$3,672	$510	$1,836
1c - Semiannual	$1,164	$4,186	$582	$2,093	$1,140	$4,100	$570	$2,050
Low Production Well Sites								
1a - Annual	$1,360	$4,893	$680	$2,446	$1,335	$4,804	$668	$2,402
1b - Stepped	$1,445	$5,200	$723	$2,600	$1,418	$5,101	$709	$2,550
1c - Semiannual	$1,616	$5,814	$808	$2,907	$1,583	$5,695	$792	$2,847

The data submitted by GPA consisted of 110 gathering and boosting compressor stations, located in Wyoming, Colorado, Ohio, Oklahoma, and Texas. OGI was used for monitoring at 104 of the gathering and boosting stations, and Method 21 was used at the remaining 6 gathering and boosting stations. Because of the differences in control effectiveness as presented in Table 2.14, the EPA estimated a percent leaking based on the OGI monitoring events separately from the Method 21 monitoring events. For the OGI data presented, the EPA calculated an average percent leaking of 0.47%. It is important to note that GPA submitted data that represented multiple monitoring events for each station, typically spanning several years. Therefore, the EPA also calculated an average percent leaking of 1.31% based on the maximum percent leaking reported for each station. The EPA performed 2 comparisons of the cost of control using the initial and average percent leaking values of 1.31% and 0.47%.

The data submitted by Target consisted of 104 transmission compressor stations, located in Oklahoma, Pennsylvania, Tennessee, Louisiana, Texas, Ohio, New York, South Carolina, and West

[43] See memorandum *EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API* located at Docket ID No. EPA-HQ-OAR-2017-0483. April 17, 2018.

Virginia. For 10 of these compressor stations, Target presented monitoring results that represented 4 consecutive quarters of monitoring under the requirements in the 2016 NSPS OOOOa. On average, Target reported 2.4 compressors per compressor station, with approximately 500-700 fugitive emissions components per compressor located at the station. Using this information, the EPA estimated an average of 1,440 fugitive emissions components per transmission compressor station in the Target data set. The EPA then calculated the initial percent leaking as 0.71% for the 10 compressor stations presented in the information. The EPA then applied the 0.71% leaking to transmission and storage stations in the model plant analysis to compare the cost of control to that calculated using EPA's 1.18%. Additionally, for these 10 compressor stations, the EPA calculated an average percent leaking value of 0.43%. As presented in section 2.5, the EPA is presenting a comparion of the industry-based cost of control to EPA's estimated value as a weighted average across all compressor station subtypes, as presented in Tables 2-~~24~~-26 and 2-~~25~~-27.

Table 2-~~24~~26. Comparison of Initial Monitoring Cost of Control Options at Compressor Stations (without cost savings)

Option	Cost of Control (1.18% leaking)				Cost of Control (1.31% leaking-0.71% leaking)[a]			
	Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)		Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Non-Low Production Well Sites								
1a - Annual	$557	$2,414	$278	$1,207	$569	$2,465	$284	$1,233
1c - Semiannual	$652	$2,827	$326	$1,413	$668	$2,895	$334	$1,448
1d - Quarterly	$910	$3,946	$455	$1,973	$934	$4,049	$467	$2,024

[a] The 1.31% value is applied to repairs at gathering and boosting stations. The 0.71% value is applied to repairs at transmission and storage stations.

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Table 2-~~25~~27. Comparison of Subsequent Monitoring Cost of Control Options at Compressor Stations (without cost savings)

Option	Cost of Control (1.18% leaking)				Cost of Control (0.47% leaking-0.43% leaking)[a]			
	Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)		Single-Pollutant ($/ton)		Multi-Pollutant ($/ton)	
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Non-Low Production Well Sites								
1a - Annual	$557	$2,414	$278	$1,207	$396	$1,718	$198	$859
1c - Semiannual	$652	$2,827	$326	$1,413	$438	$1,899	$219	$950
1d - Quarterly	$910	$3,946	$455	$1,973	$589	$2,555	$295	$1,278

[a] The 0.47% value is applied to repairs at gathering and boosting stations. The 0.43% value is applied to repairs at transmission and storage stations.

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VOLUME 2: NATIONAL LEVEL IMPACTS

3.0 NATIONWIDE IMPACTS FOR FUGITIVE EMISSIONS STANDARDS

3.1 Nationwide Costs and Emissions from Affected Sources

Similar to the approach used to calculate emissions, nationwide emissions were calculated by using the emissions calculated for the non-low production well site, low production well site, and compressor station model plants. These model plant emissions were used to estimate the baseline emissions, and the change in emissions for the sources affected by this reconsideration as a result of changing compliance activities. In this section we describe how we estimated the baseline emissions and costs, and incremental costs and emissions change related to a suite of alternative options. The incremental costs and emissions are the difference between the costs and emissions attributed to sources affected by this proposal from the baseline of costs and emissions.

3.2 Updated Baseline

The baseline used in this analysis represents our estimation of how the oil and natural gas industry looks today. This includes an estimate of the number of sources that are subject to the 2016 NSPS OOOOa using the same methods as were used in the 2016 NSPS analysis. A description of these methods is in the 2016 NSPS Final TSD and 2016 RIA. Where possible, we updated the information used, including sources of information, as described below. For well sites, we used an estimate of the number of oil and natural gas wells, along with a year by year rate of change in the number of new oil and natural gas wells to project the number of affected oil and natural gas wells from a base year, in this case 2014, through 2025. For gathering and boosting stations and transmission and storage facilities, we estimated an average number of new facilities per year.

3.2.1 Activity Data

Data from oil and natural gas technical documents and inventories, including previous TSDs for oil and gas actions, were used to estimate the number of new sources for each of the oil and natural gas segments. Information from the DrillingInfo HPDI® database and GHG Inventory were updated from the

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2016 NSPS OOOOa analysis. DrillingInfo was used to estimate the number of new well sites in 2014, as explained in section 3.2.2. The GHG Inventory to update the equipment counts for well sites and gathering and boosting stations in 2014, as explained in section 2.3.2. While equipment counts for the transmission and storage stations were not updated for the model plants, we used the GHG Inventory to estimate the number of new gathering and boosting, transmission, and storage compressor stations, and other equipment in the transmission and storage segment, such as compressors and pneumatic controllers, as explained in section 3.2.3.

3.2.2 Number of Well Sites

The DrillingInfo database provided the information on the total number of oil and natural gas wells completed or recompleted in 2014 in the U.S. The base year of 2014 was chosen for two reasons. First, it predated the proposal for the 2016 NSPS OOOOa, therefore activity in that year was not affected by those requirements. Second, there is significant variation in how quickly information from all states is included in DrillingInfo data, resulting in potential data gaps if a year after 2014 was chosen. The DrillingInfo data includes information on GOR, location, and production. The EPA used this data to calculate the number of affected sources for each sub-type of model plant based on the GOR and initial production information, which characterized completion status, use of hydraulic fracturing, and location of the well. The GOR categories are gas wells (GOR greater than 100,000), oil with associated gas wells (GOR less than 100,000 and greater than 300), and heavy oil wells (GOR less than 300). Wells are categorized by GOR based on the total production in the base year (2014).

As described in section 2.3.2, the EPA evaluated the emission reductions and cost of control for low production well sites where the average combined oil and natural gas production is less than 15 boe per day averaged over the first 30 days of production separately from that of non-low production well sites. We used production information from the DrillingInfo data to categorize each affected well as low production (less than 15 boe per day production) or non-low production (greater than 15 boe per day production). These production levels were based on the initial production reported in DrillingInfo. The DrillingInfo field 'PRAC_IP_BOE' was used, which includes both liquid and gas production and is based on the second month production recorded for the well. The second month was used to represent practical initial production because the first month record may be a partial month depending on when production started. After estimating the number of new wells based on each subcategory and subtype that are subject to the 2016 NSPS OOOOa, we applied the same assumption of 2 wells per well site as used in the model plant analysis to obtain the number of each well site subject to the 2016 NSPS OOOOa.

Additionally, the EPA published final amendments to the 2016 OOOOa rule on March 12, 2018 that created separate fugitives monitoring and repair requirements for well sites on the Alaskan North Slope.[44] In summary, these amendments granted additional time for initial monitoring during cold weather months, and required annual monitoring for these well sites. We used the location information from DrillingInfo to identify these well sites, and those in the states identified in section 3.2.2.1 subject to fugitive emissions standards under state regulations.

Table 3-1 shows the count of well sites in the base year (2014) for each model plant. In this table, wells are broken out into states of particular interest, including Alaska, California, Colorado and Texas.

Table 3-1. Well Completions in 2014 by Production Level and Well Type

	Non-low production wells			Low production wells		
Location	**Natural Gas**	**Oil** *(GOR >300)*	**Oil** *(GOR < 300)*	**Natural Gas**	**Oil** *(GOR >300)*	**Oil** *(GOR < 300)*
Alaska/North-Slope	2	59	2	0	4	0
Alaska/Other	14	6	1	6	1	0
California	9	298	575	2	133	581
Colorado	284	1,035	44	33	20	16
Louisiana	231	281	111	23	50	407
North Dakota	0	2,081	138	0	48	17
New Mexico	43	950	55	12	116	27
Ohio	169	290	10	71	97	134
Oklahoma	341	1,383	421	63	71	231
Pennsylvania	605	103	6	64	408	337
Texas	973	10,302	1,397	141	1,176	1,459
Utah	122	558	42	12	131	9
Wyoming	255	549	113	55	20	65
Other states	954	484	780	335	169	1,058

Source: DrillingInfo database extracted January 2018.[45]

We used the Energy Information Association's 2018 Annual Energy Outlook (AEO) projection of wells drilled in the contiguous 48 states to estimate a year by year rate of change from 2014 through 2025. We applied that year by year rate of change to the estimated number of wells in 2014 from DrillingInfo, regardless of well type, to project the estimated number of new well sites through 2025, scaled to the AEO oil and natural gas drilling activity projections. The estimated number of new or modified facilities using

[44] 83 FR 10628.

[45] Memorandum to Jameel Alsalam, EPA, Elizabeth Miller, EPA, and Melissa Weitz, EPA from Casey Pickering, ERG and Robyn Reid, ERG titled, *DI Desktop Data Processing Overview for OAP/OAQPS* located at Docket ID No. EPA-HQ-OAR-2017-0473. February 6, 2018.

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this well-drilling based approach rises and falls in each projection year depending on projected oil and gas drilling activity from the AEO. This approach was used to support the regulatory impacts assessment process to reflect the 2016 NSPS OOOOa impacts from the effective date through 2025.

3.2.2.1 State Regulations that Address Fugitive Emissions at Well Sites

In the process of estimating fugitive emissions controls at well sites in the baseline and regulatory options, EPA accounted for wells that were assumed to be covered by state regulations. In cases where state regulations would achieve equal or greater controls as the 2016 NSPS OOOOa controls, the regulatory options in this reconsideration do not result in a change in applied controls. Based on our research, ~~four~~five states have enacted regulations we believe meet or exceed the 2016 NSPS OOOOa standard for fugitive emissions: California, Colorado, Ohio, Pennsylvania, and Utah. These states are broken out in Table 3-1 above, and consist of just ~~under 14~~over 18% of the total number of well sites in the base year (2014). Below is a brief discussion[46] of these state regulations:

- California: On July 17, 2017, the California Air Resources Board finalized fugitive emissions requirements for well sites.[47] Beginning January 1, 2018, owners and operators of well sites were required to conduct weekly auditory, visual, and olfactory (AVO) inspections and quarterly monitoring using Method 21. OGI is allowed as a screening tool. Operators are required to repair components with a Method 21 instrument reading of 10,000 ppm or greater. Beginning January 1, 2020, the requirements change such that components with a Method 21 instrument reading of 1,000 ppm or greater are subject to repair.

- Colorado: Colorado issued revisions to Regulation 7 effective October 15, 2014 and June 30, 2018.[48] Owners/operators are required to inspect components for leaks using an approved instrument monitoring method (AIMM). There are two sets of requirements: one for ozone nonattainment areas, and one for the rest of the state. The requirements are similar in that inspections are required at set frequencies using Method 21, an OGI camera, or other Division approved instrument based monitoring method or device, in addition to monthly AVO inspections. Inspection frequencies are based on the site-wide VOC emissions, such that for well sites in ozone nonattainment areas monitoring is either annual (1-6 tpy VOC) or semiannual (>6 tpy), and for the

[46] For more details about the individual state regulations as they relate to fugitive emissions requirements, see *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa* available at Docket ID No. EPA-HQ-OAR-2017-0483.
[47] California requirements available at https://www.arb.ca.gov/regact/2016/oilandgas2016/ogfro.pdf.
[48] Colorado regulations available at https://www.colorado.gov/pacific/sites/default/files/5-CCR-1001-9_0.pdf.

rest of the state varying from one time inspections to annual inspections (*i.e.,* 0-6 tpy - one-time, 6-12 tpy -annually, 12-50 tpy -quarterly, or >50 tpy -monthly).

- Ohio: On May 19, 2014 Ohio EPA approved two types of General Permits for (1) oil and gas well-site production operations (small flares and large flares) and (2) high volume horizontal hydraulic fracturing. These General Permits are for facilities that emit less than 1 ton per year of any toxic air contaminant (not including hazardous air pollutants emitting sources that are subject to 40 CFR Part 63, Subpart HH). [49] Under the General Permits, operators are required to develop and implement a site-specific LDAR program for ancillary equipment (*e.g.,* vent, compressor, PRD, flange, etc.) that requires monitoring using OGI or Method 21. During the first year, quarterly monitoring is required, and the monitoring frequency varies based on performance in subsequent years.[50]

- Pennsylvania: On June 7, 2018, the Pennsylvania Department of Environmental Protection finalized a General Permit for unconventional oil and gas well sites. Under the General Permit, operators are required to conduct fugitives monitoring for various components (*e.g.,* vent, connectors, PRDs, OELs, etc.) using OGI or Method 21 at 500 ppm. Monitoring is required within 60 days of startup and quarterly thereafter.[51]

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- Utah: On January 3, 2018, the Utah Department of Environmental Quality approved a Permit by Rule (PBR) for well sites that are not major sources as defined in Utah Administrative Code R. 307-101-2.[52] Beginning March 2, 2018, well sites where storage tank and dehydrator emissions are greater than 4 tpy VOC are required to conduct semiannual monitoring for fugitive emissions. The PBR requirements cover all components in the proposed technical reconsideration, with the exception of thief hatches and other openings on controlled storage vessels. Monitoring is required with OGI or Method 21 with a leak definition of 500 ppm.

It should be noted that even though the EPA considered the Wyoming regulations to be equivalent for the 2016 NSPS OOOOa RIA, it is no longer considered to be equivalent because the requirements only apply to the Upper Green River Basin, as opposed to the entire state. In addition, the EPA is

[49] EPA regulations available at https://www.ecfr.gov/cgi-bin/text-idx?node=sp40.11.63.hh.
[50] Ohio regulations available at http://www.epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf and http://epa.ohio.gov/dapc/genpermit/genpermits.aspx#127854016-available-permits.
[51] Pennsylvania regulations available at http://www.dep.pa.gov/Business/Air/BAQ/Permits/Pages/GeneralPermits.aspx
[52] Utah regulations are available at https://www.utah.gov/pmn/files/359797.pdf#page=2.

considering the Texas Standard Permit requirements to be equivalent to those in the proposed standard; however, most operators within the state are subject to the requirements of the permit by rule, which are not considered to be equivalent. Therefore, the EPA is not including the Texas regulations in the corresponding RIA analysis. Pennsylvania's General Permit 5 is considered to be equivalent to the rule; however, this permit only applies to compressor stations and will not be included in the RIA analysis because we do not currently have the data to separate compressor stations out by state.

3.2.3 Gathering and Boosting Stations and Transmission and Storage Compressor Stations

In addition to well sites, the fugitive emissions requirements apply to gathering and boosting stations, transmission compressor stations, and storage compressor stations. The GHG Inventory is used to estimate the count of newly affected compressor stations in each year. The GHG Inventory uses a variety of data sources and studies to estimate equipment counts and emissions. Many equipment counts are based on the data reported under the GHGRP, scaled up to reflect the total population including both GHGRP-reporting and non-reporting oil and natural gas facilities.

We estimated the number of new compressor stations, by type, by averaging the increases in the year-to-year changes in total national counts of equipment over the 10-year period from 2004 through 2014. Year-to-year increases were assumed to represent newly constructed facilities. Decreases in total counts were represented as zeros for that year, and average together with the annual increases. This approach results in the same number of new compressor stations in each projected year, regardless of increases or decreases in AEO projected drilling or production. These values reflect that construction of compressor stations and transmission pipelines are longer-term investments not necessarily correlated with short-term fluctuations in production. In addition, this approach may result in fewer total new and modified compressor stations for two reasons: (1) modifications of existing compressor stations are not captured, and (2) if existing compressor stations are closed and replaced with new facilities, those would not be reflected in the net increase in the year-to-year total. The national equipment counts estimated in the GHG Inventory are not disaggregated by state, therefore, activity data using this approach is only estimated at the national level. The average year-to-year increase for compressor stations is summarized in Table 3-2.

Table 3-2. Average Year-to-Year Increases in Compressor Station Counts

Location	Average Year-to-Year Increase
Gathering and Boosting Stations	212
Transmission Compressor Stations	36
Storage Compressor Stations	2

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3.2.4 Baseline Emission Estimates

The nationwide baseline emissions were calculated using the model plant data and the estimated number of new and modified sources for each of the segments, as explained above. The baseline nationwide emissions were estimated assuming all 2016 NSPS OOOOa sources are complying with that regulation. The nationwide emission estimates for the total number of oil and natural gas production well sites, gathering and boosting stations, and transmission and storage facilities that we estimate are complying with the fugitive emission requirements in the 2016 NSPS OOOOa are summarized in Table 3-3. The summary includes baseline emissions for each of these segments for projected year 2025, assuming no changes to the standards already in place.

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Table 3-3. Nationwide Baseline Emissions for Sources Subject to Fugitive Emissions Monitoring in Year 2025

Oil and Gas Segment	Number of Sources Subject to NSPS[a]	Methane Emissions (tpy)	VOC Emissions (tpy)
Non-Low Production Well Sites	**79,616**	**~~105,235~~102,852**	**~~29,253~~28,590**
Natural Gas Well Sites	12,219	~~28,871~~26,687	~~8,025~~7,418
Oil Well Sites (GOR > 300)	56,115	67,~~803~~612	18,~~848~~794
Oil Well Sites (GOR < 300)	11,282	8,~~560~~553	2,~~380~~377
Low Production Well Sites	**23,211**	**~~21,476~~20,257**	**5,~~970~~631**
Natural Gas Well Sites	2,494	4,~~786~~599	1,~~330~~278
Oil Well Sites (GOR > 300)	7,462	~~7,646~~6,990	~~2,125~~1,943
Oil Well Sites (GOR < 300)	13,254	~~9,044~~8,668	2,~~514~~409
Compressor Stations	**2,750**	**20,216**	**4,662**
Gathering & Boosting Stations	2,332	16,390	4,556
Transmission Stations	396	3,199	89
Storage Stations	22	627	17

a. Affected facilities in 2025 includes new affected facilities in 2015 through 2025 which are assumed to still be operating in 2025.

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3.3 Nationwide Incremental Impacts of Regulatory Options

This section provides an analysis of the primary environmental impacts (*i.e.,* increase in emissions), cost impacts, and secondary environmental impacts related to the regulatory options which were selected as a viable options for reducing fugitive emissions from fugitive emissions components located at well sites and compressor stations under this proposed reconsideration.

Based on the discussion above, the EPA reconsidered Regulatory Options 1a, 1b and 1c for well sites and Regulatory Options 1a, 1c, and 1d for compressor stations. A summary of the options is provided below. While we also evaluated Regulatory Option 2 (Method 21 monitoring), we are not presenting nationwide impacts of that option because Regulatory Option 1 (OGI monitoring) was selected as the BSER for the collection of fugitive emissions components located at well sites and compressor stations.

- Regulatory Option 1: The implementation of a fugitive emissions monitoring and repair program using OGI as the detection method. The following sub-options were evaluated for different monitoring frequencies, as shown below.

- 1a. Monitoring on an annual frequency at well sites and compressor stations.
- 1b. Monitoring on a semiannual frequency for 2 years, followed by annual monitoring thereafter at well sites.
- 1c. Monitoring on a semiannual frequency at well sites and compressor stations.
- 1d. Monitoring on a quarterly frequency at compressor stations.
- 1e. Monitoring on a biennial frequency at low production well sites.

The impacts of this reconsideration are based on the number of sources affected by this reconsideration for each option compared to the baseline of the 2016 NSPS OOOOa. The number of sources affected by this reconsideration varies across the options. For example, oil and natural gas well sites outside of the Alaskan North Slope are unaffected when regulatory option 1c is being considered as they are already required to follow the semiannual fugitive emissions monitoring and repair program, however they are affected sources under Regulatory Options 1a, and 1b. The number of oil and natural gas well sites, gathering and boosting stations, transmission stations, and storage facilities that would be subject to each of the regulatory options listed above were estimated using the same method as outlined for the baseline of affected sources as described above; namely data from the DrillingInfo database, the 2018 AEO, and the 2018 GHG Inventory. In 2025, which include all new and modified sources since 2016, it was estimated that there would be at most 12,219 natural gas well sites, 11,282 oil well sites with GOR <300, and 56,115 oil well sites with GOR >300 for non-low production well sites; 2,494 natural gas well sites, 13,254 oil well sites with GOR <300, and 7,462 oil well sites with GOR >300 for low production well sites; 2,332 gathering and boosting stations, 396 transmission stations, and 22 storage facilities subject to these options.

3.3.1 Primary Environmental Impacts of Regulatory Options as a Change from the Baseline

As described in section 2.4.1.2, we estimated that a fugitive emissions monitoring and repair program can achieve an overall ~~40~~30 percent reduction in VOC and methane emissions at a biennial monitoring frequency, 40 percent reduction at an annual monitoring frequency, 45 percent reduction at a stepped monitoring frequency, 60 percent reduction at a semiannual monitoring frequency, and 80 percent reduction at a quarterly monitoring frequency. Nationwide emission reductions were estimated by applying these same percentages to the uncontrolled baseline emissions for well sites and compressor stations at the various frequencies.

To illustrate the effects of the options, we provide the forgone emission reductions (or the increase in emissions) for each of the options. There are forgone emission reductions because options 1a, 1b, and

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~~1b~~1c are less frequent than the baseline monitoring frequency for well sites, and options 1a and 1c are less frequent than the baseline monitoring frequency for compressor stations. Table 3-4 summarizes the forgone emission reductions for the options with less frequent monitoring than the baseline.

Table 3-4. Nationwide Forgone Emission Reductions for Sources Subject to Fugitive Emissions Monitoring in Year 2025

Oil and Gas Segment	Methane Emissions (tpy)	VOC Emissions (tpy)
Non-Low Production Well Sites		
Option 1a – Annual	~~46,093~~43,708	12,~~812~~150
Option 1b - Stepped	~~34,569~~32,781	9,~~609~~113
Option 1c – Semiannual[a]	--	--
Low Production Well Sites		
Option 1a – Annual	~~9,378~~8,158	2,~~608~~268
Option 1b - Stepped	~~7,034~~6,119	1,~~955~~701
Option 1c – Semiannual[a]	--	--
Option 1e – Biennial	12,242	3,403
Compressor Stations		
Option 1a – Annual	40,432	9,324
Option 1c - Semiannual	20,216	4,662
Option 1d – Quarterly[a]	--	--

a. Options 1c and 1d are the same as the baseline for well sites and compressor stations, respectively, therefore, forgone emission reductions are not applicable to these monitoring frequencies.

3.3.2 Natural Gas Savings as a Change from the Baseline

The implementation of a fugitive emissions monitoring and repair program will result in savings of natural gas, which can offset compliance costs. The change in natural gas savings for each of the OGI monitoring options was evaluated for this reconsideration as described below. We are not presenting this information for Options 2 or 3 because Method 21 is an alternative to OGI monitoring in this reconsideration.

OGI Monitoring. The various monitoring frequencies under Regulatory Option 1 (OGI monitoring) were evaluated to determine the change in natural gas savings from each monitoring frequency. In 2025, under Option 1a, annual monitoring, the potential natural gas saved at non-low

production well sites was calculated to decrease by ~~714,697~~588,119 standard cubic feet per year (scf/yr) for natural gas production well sites, 1.7 million scf/yr for oil well sites with a GOR <300, and 219,~~914~~478 scf/yr for oil well sites with a GOR >300. Similarly, for low production well sites, the natural gas saved under an annual monitoring frequency in 2025 was calculated to decrease by ~~118,805~~107,927 scf/yr for natural gas production well sites, ~~191,704~~211,179 scf/yr for oil well sites with a GOR <300, and ~~232,982~~153,717 scf/yr for oil well sites with a GOR >300. For the compressor stations, the potential natural gas saved in 2025 was calculated to decrease by 1.9 million scf/yr for gathering and boosting stations, 331,222 Mscf/yr for transmission stations, and 64,891 Mscf/yr for storage facilities.[53]

Under Option 1b, semiannual monitoring for 2 years followed by annual monitoring, the potential natural gas saved in 2025 at non-low production well sites was calculated to decrease by ~~536,023~~441,089 scf/yr for natural gas production well sites, 1.3 million scf/yr for oil well sites with a GOR <300, and 164,~~936~~608 scf/yr for oil well sites with a GOR >300. Similarly, for low production well sites, the natural gas saved in 2025 under the stepped monitoring frequency was calculated to decrease by ~~89,103~~80,945 scf/yr for natural gas production well sites, ~~143,778~~158,384 scf/yr for oil well sites with a GOR <300, and ~~174,737~~115,288 scf/yr for oil well sites with a GOR >300. We did not evaluate the stepped monitoring frequency for compressor stations as part of this reconsideration.

Under Option 1c, semiannual monitoring, we did not evaluate the change in the natural gas saved for well sites, as they perform semiannual monitoring under the baseline. For the compressor stations, the potential natural gas saved in 2025 was calculated to decrease by 949,865 scf/yr for gathering and boosting stations, 165,611 scf/yr for transmission stations, and 32,446 scf/yr for storage facilities.

~~Finally, under~~Under Option 1d, quarterly monitoring, we did not evaluate a change in the natural gas saved, because compressor stations perform quarterly monitoring under the baseline, and we did not evaluate the quarterly monitoring frequency for non-low production well sites or low production well sites as part of this reconsideration.

Finally, under Option 1e, biennial monitoring, the potential natural gas saved in 2025 at low production well sites was calculated to decrease by 161,890 scf/yr for natural gas production well sites, 316,768 scf/yr for oil well sites with a GOR <300, and 230,762 scf/yr for oil well sites with a GOR >300.

[53] Natural gas savings calculated using the methane reductions and assuming a methane to natural gas volume ration of 82.9% for upstream facilities (well sites, gathering & boosting) and a methane to natural gas volume ratio of 92.8% for downstream facilities (transmission, storage).

We did not evaluate the biennial monitoring frequency for non-low production well sites or compressor stations as part of this reconsideration.

Operators in the transmission and storage segments of the industry typically do not own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, the unit-level cost and emission reduction analyses supporting BSER decisions in the preamble (and is presented in Volume 1 of the TSD) do not include estimates of revenue from natural gas recovery as offsets to compliance costs. From a social perspective, however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in the national impacts analysis. An economic argument can be made that, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the most simple and transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of these revenues across agents. This is the approach followed in Volume 2 of the TSD, as well as in the RIA.

To estimate the value of the natural gas saved, we used the AEO's projection of the price of natural gas. The AEO projects Henry Hub natural gas prices in $/MMBtu in 2017 dollars.[54] We adjust those prices to $/Mcf (using the conversion of 1 MMBtu = 1.028 Mcf) in 2016 dollars (using the GDP-Implicit Price Deflator) at the wellhead.[55] For example, the AEO Henry Hub price for natural gas is projects to be $4.07/MMBtu in 2017$ in 2025. After adjustments, the value for natural gas that we used for 2025 was $2.70/Mcf.

[54] Available at: http://www.eia.gov/forecasts/aeo/tables_ref.cfm.
[55] An EIA study indicated that the Henry Hub price is, on average, about 11 percent higher than the wellhead price. See http://www.eia.gov/oiaf/analysispaper/henryhub/.

3.3.3 Cost Impacts as a Change from the Baseline

Similar to the discussion in sections 2.4.1.3, 2.4.2.3, and 2.5, we applied the regulatory cost of the rule for the model plants to the total predicted number of sources nationwide to estimate the total cost impacts of the fugitive emissions requirements. These costs include the capital costs or initial costs of the requirements (*e.g.*, initial setup of the monitoring plan, initial notification, and initial monitoring costs) and annual costs of the requirements (*e.g.*, subsequent monitoring event planning, conducting subsequent monitoring, repairs, and submission of annual reports). Additionally, we have taken into account the value of the saved natural gas, as discussed in section 3.3.2 and section 2.4.1. Tables 3-5a through 3-5d summarize the change in the nationwide cost impacts and forgone emission reductions for each of the OGI monitoring frequencies in Regulatory Option 1, compared to the baseline, for the year 2025. Similar information for other years that were evaluated is included as Attachment 1 to this document.

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Table 3-5a. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Projected Year 2025						
Non-Low Production Well Sites	**79,616**	**~~68,933~~66,752**	**~~46,093~~43,708**	**12,~~812~~150**	**$~~70.59~~68.36**	**$~~60.71~~58.99**
Gas Well Sites	12,219	~~10,430~~8,583	~~12,333~~10,148	~~3,428~~2,821	$~~10.68~~8.79	$~~8.04~~6.61
Oil Well Sites (GOR > 300)	56,115	~~49,276~~48,961	29,~~965~~773	8,~~329~~276	$50.4~~6~~14	$~~44.04~~43.76
Oil Well Sites (GOR < 300)	11,282	9,~~227~~208	3,~~795~~787	1,~~055~~053	$9.4~~5~~43	$8.~~6~~462
Low Production Well Sites	**23,210**	**~~19,416~~16,946**	**~~9,378~~8,158**	**2,~~608~~268**	**$~~19.88~~17.35**	**$~~17.87~~15.60**
Gas Well Sites	2,494	~~2,134~~1,939	~~2,050~~1,862	~~570~~518	$~~2.19~~1.99	$1.~~75~~59
Oil Well Sites (GOR > 300)	7,462	~~6,287~~5,041	~~3,308~~2,652	~~920~~737	$~~6.44~~5.16	$~~5.73~~4.59
Oil Well Sites (GOR < 300)	13,254	~~10,995~~9,966	~~4,020~~3,644	1,~~118~~013	$~~11.26~~10.21	$~~10.40~~9.42
Well Sites Total	**102,826**	**~~88,349~~83,698**	**~~55,471~~51,866**	**~~15,420~~14,418**	**$~~90.47~~85.71**	**$~~78.58~~74.59**
Compressor Stations						
Gathering & Boosting	2,332	2,332	32,781	9,112	$43.18	$36.15
Transmission	396	396	6,398	177	$7.23	$6.01
Storage	22	22	1,253	35	$0.67	$0.43
Compressor Stations Total	**2,750**	**2,750**	**40,432**	**9,324**	**$51.08**	**$42.59**

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Table 3-5b. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Projected Year 2025						
Non-Low Production Well Sites	**79,616**	**~~68,933~~66,752**	**~~34,569~~32,781**	**9,~~609~~113**	**$~~52.94~~51.27**	**$~~45.53~~44.24**
Gas Well Sites	12,219	~~10,430~~8,583	~~9,249~~7,611	2,~~571~~116	$~~8.01~~6.59	$~~6.03~~4.96
Oil Well Sites (GOR > 300)	56,115	~~49,276~~48,961	22,~~474~~330	6,~~247~~207	$37.~~85~~60	$~~33.03~~32.82
Oil Well Sites (GOR < 300)	11,282	9,~~227~~208	2,~~846~~840	~~791~~790	$7.~~09~~07	$6.~~48~~46
Low Production Well Sites	**23,210**	**~~19,416~~16,946**	**~~7,034~~6,119**	**1,~~955~~701**	**$~~14.91~~13.01**	**$~~13.40~~11.70**
Gas Well Sites	2,494	~~2,134~~1,939	1,~~538~~397	~~427~~388	$1.~~64~~49	$1.~~31~~19
Oil Well Sites (GOR > 300)	7,462	~~6,287~~5,041	~~2,481~~1,989	~~690~~553	$~~4.83~~3.87	$~~4.30~~3.45
Oil Well Sites (GOR < 300)	13,254	~~10,995~~9,966	~~3,015~~2,733	~~838~~760	$~~8.44~~7.65	$7.~~80~~07
Well Sites Total	**102,826**	**~~88,349~~83,698**	**~~41,603~~38,900**	**~~11,564~~10,814**	**$~~67.86~~64.28**	**$~~58.93~~55.94**

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Table 3-5c. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Projected Year 2025						
Non-Low Production Well Sites	**79,616**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	12,219	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	56,115	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	11,282	0	0	0	$0.00	$0.00
Low Production Well Sites	**23,210**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	2,494	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	7,462	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	13,254	0	0	0	$0.00	$0.00
Well Sites Total	**102,826**	**0**	**0**	**0**	**$0.00**	**$0.00**
Compressor Stations						
Gathering & Boosting	2,332	2,332	16,390	4,556	$28.79	$25.27
Transmission	396	396	3,199	89	$4.82	$4.21
Storage	22	22	627	17	$0.45	$0.33
Compressor Stations Total	**2,750**	**2,750**	**20,216**	**4,662**	**$34.06**	**$29.81**

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Table 3-5d. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Projected Year 2025						
Compressor Stations						
Gathering & Boosting	2,332	0	0	0	$0.00	$0.00
Transmission	396	0	0	0	$0.00	$0.00
Storage	22	0	0	0	$0.00	$0.00
Compressor Stations Total	**2,750**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table 3-5e. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Projected Year 2025						
Low Production Well Sites	**23,210**	**16,958**	**12,242**	**3,403**	**$26.04**	**$23.41**
Gas Well Sites	2,494	1,939	2,794	777	$2.98	$2.38
Oil Well Sites (GOR > 300)	7,462	5,053	3,982	1,107	$7.75	$6.90
Oil Well Sites (GOR < 300)	13,254	9,966	5,466	1,519	$15.31	$14.14

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4.0 NATIONWIDE IMPACTS FOR CERTIFICATIONS

4.1 Nationwide Impacts of Regulatory Options

4.1.1 Approach

Nationwide impacts of certifications for closed vent system design and technical infeasibility of routing pneumatic pumps to an existing control device were calculated by estimating the count of affected facilities installed in a typical year and multiplying by the estimated cost per certification. Closed vent system and technical infeasibility certifications impact pneumatic pumps, centrifugal compressors, reciprocating compressors, and storage vessels. Unit level emissions and control cost estimates are unchanged in this action, and can be found in the 2016 NSPS Final TSD.[56]

4.1.2 Nationwide Activity Data for Equipment Requiring Certifications

4.1.2.1 Pneumatic Pumps and Compressors

The count of new pneumatic pumps and compressors installed in a typical year was estimated by determining the rate of change in the count of each source based on a review of the annual count of each source from the year 2005 through 2016 as reported in the 2018 GHG Inventory for natural gas and oil production facilities. The EPA used the same methodology in this analysis as is discussed in section 3.2.3 above. Namely, that typical new sources estimated by averaging increases in year-to-year changes in the total national counts of equipment over the 10-year period from 2005 to 2016, where a decrease is represented with a zero value.

The EPA has carried forward several assumptions from the 2016 NSPS Final TSD, including: (1) 50 percent of the pumps to be diaphragm and 50 percent of the pumps to be piston pumps, which are not affected facilities under the 2016 NSPS OOOOa; (2) no pneumatic pumps are used in the natural gas processing, natural gas transmission and storage segments; and (3) 75 percent of the new pumps will be able to be connect to an existing control device or process, and therefore will require a closed vent system design certification. In addition, we estimate that half of the remaining uncontrolled pneumatic pump affected facilities require additional certification

[56] See Docket ID No. EPA-HQ-OAR-2010-0505-7631.

for technical infeasibility of routing emissions to an existing control device, and the remaining half are uncontrolled because no control device is present. Therefore, we estimate an additional 12.5 percent of pneumatic pumps require a certification for technical infeasibility. The average number of new pneumatic pumps per year estimated from the 2018 GHG Inventory is about 4,336. Using the assumptions above, the average number certifications related to pneumatic pumps is 3,794. The results of this analysis are shown in Table 4-1.

The 2016 NSPS OOOOa requires closed vent system certification for all centrifugal compressor affected facilities, therefore, we assume 100 percent of these sources require certification. The average number of new ~~centrifigual~~centrifugal compressors from the GHGI is estimated to be 18 per year. The 2016 NSPS OOOOa allows an option for reciprocating compressor affected facilities to route emissions to a process; therefore, we estimate 10 percent of the reciprocating compressor affected facilities require a certification. The average number of new reciprocating compressors from the GHG Inventory is estimated to be 76 per year. Under that 10 percent assumption above, we estimated an average of 8 certifications related to centrifugal compressors per year. Table 4-1 presents the estimated counts of certification on pneumatic pumps and compressors in a typical year.

Table 4-1. Estimated Count of Certifications by Source in a Typical Year

Source	Count of Certifications
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Total	3,820

4.1.2.2 Storage Vessels

The methodology to determine the number of affected closed vent systems on storage vessels that are subject to certification requirements under the 2016 NSPS OOOOa closely follows the procedure used to estimate the number of storage vessels subject to the 2012 NSPS OOOO.[57] For the analysis performed during this reconsideration, we updated the data set by

[57] See memorandum to Bruce Moore, U.S. EPA from Heather Brown, EC/R. "Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector". April 2013. Docket ID No. EPA-HQ-OAR-2010-0505-4597.

updating the base year, and did not reduce the count of storage vessels controlled under existing state regulations, as there are no closed vent system certification requirements in existing regulations. The steps below were used to determine the number of storage vessels subject to the closed vent system certification requirements.

Step 1: Develop a dataset of newly completed wells in 2014

This analysis assumes that there is one new storage vessel with a closed vent system requiring certification per new well completed. The 2014 DrillingInfo data extraction, which includes production levels, location, and year the well was completed was used to assemble a dataset of wells completed in 2014. To do so, we followed the same process as described in section 3.2.2.

Step 2: Distribute the wells across production rate brackets

We then separated the wells into subcategories based on the production levels and calculated the boe per day from each well. Next we further separated the wells within each subcategory based on the subtype of well (*i.e.,* natural gas well and oil well). Using the boe for each well, we distributed the wells across the production brackets as shown in Table 4-4. This provides the estimated number of crude oil storage vessels (from oil wells) and condensate storage vessels (from natural gas wells) in each production bracket.

Step 3: Estimate emissions from a typical storage vessel within each production bracket

Average storage vessel emissions factors, in terms of mass of emissions per throughput, were developed in support of the 2012 NSPS OOOO.[58] These emissions factors were developed using the American Petroleum Institute's (API's) E&P Tanks program and more than 100 storage vessels across the country with varying characteristics.[59]

Uncontrolled VOC Emissions from Crude Oil Storage Vessels = 0.214 tpy VOC bbl/day

[58] U.S. Environmental Protection Agency. Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for Proposed Standards. April 2012. Docket ID EPA-HQ-OAR-2010-0505-4550.
[59] Production Tank Emissions Model. E&P Tank Version 2.0. A Program for Estimating Emissions from Hydrocarbon Production Tanks. American Petroleum Institute. Software Number 4697. April 2000.

Uncontrolled VOC Emissions from Condensate Storage Vessels = 2.09 tpy VOC/bbl/day

To estimate the emissions from an average storage vessel within each production rate bracket, we developed average production rates for each bracket using EIA published nationwide production per well per day for each production bracket from 2006 through 2009.[60] Table 4-4 presents the average oil production and condensate production in barrels per well per day, respectively. For this analysis, we considered the liquid produced from oil wells to be crude oil and from gas wells to be condensate.

The average VOC emissions for each new storage vessel within each production rate bracket were calculated by applying the average production rate (bbl/day) to the VOC emission factor (tpy VOC/bbl/day) and are presented in Table 4-2.

Table 4-2. Average Oil and Condensate Production and Storage Vessel Emissions per Production Rate Bracket[61]

Production Rate Bracket (boe/day)[a]	Oil Wells		Gas Wells	
	Average Oil Production Rate per Oil Well (bbl/day)[b]	Crude Oil Storage Vessel VOC Emissions (tpy)[c]	Average Condensate Production Rate per Gas Well (bbl/day)[b]	Condensate Storage Vessel VOC Emissions (tpy)[c]
0- 1	0.385	0.083	0.0183	0.038
1- 2	1.34	0.287	0.0802	0.168
2- 4	2.66	0.570	0.152	0.318
4- 6	4.45	0.953	0.274	0.573
6- 8	6.22	1.33	0.394	0.825
8- 10	8.08	1.73	0.499	1.04
10- 12	9.83	2.11	0.655	1.37
12- 15	12.1	2.59	0.733	1.53
15- 20	15.4	3.31	1.00	2.10
20- 25	19.9	4.27	1.59	3.32

[60] Memorandum. Heather Brown, EC/R Incorporated to Bruce Moore, EPA/OAQPS/SPPD/FIG. Revised Analysis to Determine the Number of Storage Vessels Projected to be Subject to New Source Performance Standards for the Oil and Natural Gas Sector. April 8, 2013.
[61] Ibid.

Production Rate Bracket (boe/day)[a]	Oil Wells		Gas Wells	
	Average Oil Production Rate per Oil Well (bbl/day)[b]	Crude Oil Storage Vessel VOC Emissions (tpy)[c]	Average Condensate Production Rate per Gas Well (bbl/day)[b]	Condensate Storage Vessel VOC Emissions (tpy)[c]
25- 30	24.3	5.22	1.84	3.85
30- 40	30.5	6.54	2.55	5.33
40- 50	39.2	8.41	3.63	7.59
50- 100	61.6	13.2	5.60	11.7
100- 200	120	25.6	12.1	25.4
200- 400	238	51.0	23.8	49.8
400- 800	456	97.7	44.1	92.3
800- 1,600	914	196	67.9	142
1,600- 3,200	1,692	363	148	311
3,200- 6,400	3,353	719	234	490
6,400- 12,800	6,825	1,464	891	1,864
> 12,800[d]	0	0	0	0

Minor discrepancies may be due to rounding.
[a]boe=Barrels of Oil Equivalent
[b]Oil and condensate production rates published by EIA. "US Total Distribution of Wells by Production Rate Bracket." http://www.eia.doe.gov/pub/oil_gas/petrosystem/us_table.html.
[c]Oil storage vessel VOC emission factor = 0.214 tpy VOC/bbl/day. Condensate storage vessel VOC emission factor = 2.09 tpy/bbl/day.

Step 4: Determine the number of storage vessels that would likely have uncontrolled VOC emissions greater than the NSPS applicability threshold of 6 tpy

The next step was to determine the number of storage vessels that would potentially be subject to the NSPS by having VOC emissions greater than 6 tpy. As shown in Table 4-2, crude oil storage vessels in the production rate bracket of 30 to 40 boe per day and higher have average emissions greater than 6 tpy, meaning these storage vessels would be potentially subject to the NSPS. Similarly, condensate storage vessels in the production bracket of 40 to 50 boe per day and higher have emissions greater than 6 tpy.

Step 5: Project base count of storage vessels in 2014 through to 2025

The above steps were used to estimate the number of new storage vessels in 2014. Similar to the procedure used to determine the number of new storage vessels in 2014 based on the number of new wells in 2014 in DrillingInfo, we assumed that each new well drilled is associated with a new storage vessel. As in the projection of new wells, we use the AEO projection of drilling activity to determine a year-by-year rate of change and apply that rate of change to the number of new storage vessels. We used the AEO projection of wells drilled in the contiguous 48 states to estimate a year-by-year rate of change from 2014 through 2025. We applied that year-by-year rate of change to the estimated number of wells in 2014 from DrillingInfo, regardless of well type, to project the estimated number of new well sites through 2025, scaled to the AEO oil and natural gas drilling activity projections.

The 2016 NSPS OOOOa requires closed vent system certification for all storage vessel affected facilities, therefore we assume 100 percent of these sources require certification. The results of this analysis are shown in Table 4-3.

Table 4-3. Estimated Count of Storage Vessels Installed

Year	Count of SV that Require CVS Certification Under NSPS
2019	9,597
2020	10,375
2021	10,762
2022	11,123
2023	11,413
2024	11,591
2025	11,636

4.1.2.3 Summary of Affected Facilities Requiring Certification

Table 4-4 summarizes the count of the facilities in 2025 that are affected by this reconsideration that require certification under the 2016 NSPS OOOOa in the year 2025. This information is available for years 2019 through 2025 in Attachment 2 of this TSD.

Table 4-4. Estimated Count of Affected Facilities Requiring Certifications for 2025

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	11,636
Total	15,456

4.1.3 Nationwide Cost Impacts of Selected Regulatory Options

The EPA calculated the nationwide impacts of the reconsideration proposal to allow certifications to be done by either an in-house engineer or a professional engineer. EPA estimated that the cost for a PE certification is $546.66 per certification, and the cost for an in-house engineer certification is $358.09 per certification (in 2016$). This analysis assumes a PE certification requires 4 hours of staff engineering work, and 2 hours of PE work, and an in-house certification requires 4 hours of staff engineering work. We estimate wages for staff engineers based on estimates from the Bureau of Labor Statistics, Occupational Employment Statistics,[62] and inflate wages by 5 percent for PEs, based on 2010 survey findings from the National Society of Professional Engineers.[63] We have increased wages for both staff engineers and PEs by 110 percent to account for the benefit packages available to those employed by private industry.

Table 4-5, below, shows the estimated number of sources and the estimated national costs of PE certification, as under the 2016 NSPS OOOOa, and the estimated national costs of certification by in-house engineers, as being proposed in the reconsideration, in 2025. This information is available for years 2019 through 2025 in Attachment 2 of this TSD.

[62] Mean hourly wages, Industrial Engineers, Including Health and Safety ($42.63 per hour). May 2016 National Occupational Employment and Wage Estimates, United States. https://www.bls.gov/oes/current/oes_nat.htm#17-0000.

[63] 2010 survey findings from the National Society of Professional Engineers, https://www.nspe.org/resources/press-room/press-releases/engineering-salaries-continue-rise-despite-concern-over.

Table 4-5. Summary of National Level Impact for PE Certification Alternatives in 2025

Certification Costs - 2025	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	15,456	$8,449,280
Cost Estimate for Proposed Reconsideration	15,456	$5,534,706
Reduced Burden of Proposed In-House Engineer Certification	15,456	$2,914,573

Attachment 1

Supporting Information for Nationwide Impacts of the Fugitive Emissions Requirements

Table A1-1a. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2019						
Non-Low Production Well Sites	**32,720**	**~~28,329~~27,433**	**~~18,943~~17,963**	**~~5,266~~4,993**	**$~~29.01~~28.09**	**$~~25.62~~24.88**
Gas Well Sites	5,022	~~4,286~~3,527	~~5,068~~4,171	1,~~409~~159	$~~4.39~~3.61	$~~3.48~~2.87
Oil Well Sites (GOR > 300)	23,062	20,~~251~~122	12,~~315~~236	3,~~423~~401	$20.~~74~~61	$18.~~53~~41
Oil Well Sites (GOR < 300)	4,636	3,~~792~~784	1,~~560~~556	~~434~~433	$3.88	$3.60
Low Production Well Sites	**9,539**	**~~7,979~~6,965**	**3,~~854~~353**	**~~1,071~~932**	**$~~8.17~~7.13**	**$~~7.48~~6.53**
Gas Well Sites	1,025	~~877~~797	~~843~~765	~~234~~213	$0.~~90~~82	$0.~~75~~68
Oil Well Sites (GOR > 300)	3,067	2,~~584~~072	1,~~359~~090	~~378~~303	$2.~~65~~12	$~~2.40~~1.93
Oil Well Sites (GOR < 300)	5,447	4,~~518~~096	1,~~652~~498	~~459~~416	$4.~~63~~19	$~~4.33~~3.93
Well Sites Total	**42,259**	**~~36,308~~34,398**	**~~22,797~~21,316**	**~~6,337~~5,925**	**$~~37.18~~35.23**	**$~~33.10~~31.41**
Gathering & Boosting	1,060	1,060	14,900	4,142	$19.63	$16.96
Transmission	180	180	2,908	81	$3.29	$2.82
Storage	10	10	570	16	$0.30	$0.21
Compressor Stations Total	**1,250**	**1,250**	**18,378**	**4,239**	**$23.22**	**$20.00**

Table A1-1b. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2020						
Non-Low Production Well Sites	**39,993**	**~~34,626~~33,531**	**~~23,153~~21,956**	**6,~~436~~103**	**$~~35.46~~34.34**	**$30.~~95~~06**
Gas Well Sites	6,138	~~5,239~~4,311	~~6,195~~5,098	1,~~722~~417	$~~5.37~~4.41	$~~4.16~~3.42
Oil Well Sites (GOR > 300)	28,188	24,~~752~~594	~~15,052~~14,956	4,~~184~~157	$25.~~35~~19	$22.~~42~~27
Oil Well Sites (GOR < 300)	5,667	4,~~635~~626	1,~~906~~902	~~530~~529	$4.~~75~~74	$4.~~38~~37
Low Production Well Sites	**11,659**	**~~9,753~~8,512**	**4,~~711~~097**	**1,~~309~~139**	**$~~9.99~~8.72**	**$~~9.07~~7.92**
Gas Well Sites	1,253	~~1,072~~974	~~1,030~~935	~~286~~260	$1.~~10~~00	$0.~~90~~82
Oil Well Sites (GOR > 300)	3,748	~~3,158~~2,532	1,~~662~~332	~~462~~370	$~~3.23~~2.59	$2.~~91~~33
Oil Well Sites (GOR < 300)	6,658	5,~~523~~006	~~2,019~~1,830	~~561~~509	$5.~~66~~13	$~~5.26~~4.77
Well Sites Total	**51,652**	**~~44,379~~42,043**	**~~27,864~~26,053**	**7,~~745~~242**	**$~~45.45~~43.06**	**$~~40.02~~37.98**
Gathering & Boosting	1,272	1,272	17,881	4,970	$23.55	$20.07
Transmission	216	216	3,490	97	$3.95	$3.34
Storage	12	12	684	19	$0.36	$0.25
Compressor Stations Total	**1,500**	**1,500**	**22,055**	**5,086**	**$27.86**	**$23.66**

Table A1-1c. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2021						
Non-Low Production Well Sites	**47,537**	**~~41,158~~39,857**	**~~27,521~~26,097**	**7,~~650~~255**	**$~~42.15~~40.82**	**$~~36.84~~35.78**
Gas Well Sites	7,296	~~6,227~~5,125	~~7,364~~6,059	~~2,047~~1,684	$~~6.38~~5.25	$4.~~96~~08
Oil Well Sites (GOR > 300)	33,505	29,~~422~~234	17,~~891~~777	4,~~973~~942	$~~30.13~~29.94	$26.~~68~~51
Oil Well Sites (GOR < 300)	6,736	5,~~509~~498	2,~~266~~261	~~630~~629	$5.~~64~~63	$5.~~20~~19
Low Production Well Sites	**13,858**	**~~11,593~~10,118**	**~~5,599~~4,872**	**1,~~556~~354**	**$~~11.87~~10.36**	**$~~10.79~~9.42**
Gas Well Sites	1,489	1,~~274~~158	1,~~224~~112	~~340~~309	$1.~~30~~19	$~~1.07~~0.97
Oil Well Sites (GOR > 300)	4,455	3,~~754~~010	1,~~975~~584	~~549~~440	$3.~~84~~08	$~~3.46~~2.78
Oil Well Sites (GOR < 300)	7,914	~~6,565~~5,950	2,~~400~~176	~~667~~605	$6.~~72~~09	$~~6.26~~5.67
Well Sites Total	**61,395**	**~~52,751~~49,975**	**~~33,120~~30,969**	**~~9,206~~8,609**	**$~~54.02~~51.18**	**$~~47.63~~45.20**
Gathering & Boosting	1,484	1,484	20,861	5,799	$27.48	$23.45
Transmission	252	252	4,071	113	$4.60	$3.90
Storage	14	14	798	22	$0.43	$0.29
Compressor Stations Total	**1,750**	**1,750**	**25,730**	**5,934**	**$32.51**	**$27.64**

Table A1-1d. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2022						
Non-Low Production Well Sites	**55,334**	**~~47,910~~46,394**	**~~32,034~~30,378**	**8,~~905~~445**	**$~~49.06~~47.51**	**$~~42.82~~41.60**
Gas Well Sites	8,492	~~7,249~~5,965	~~8,571~~7,053	~~2,383~~1,961	$~~7.42~~6.11	$~~5.75~~4.74
Oil Well Sites (GOR > 300)	39,001	34,~~248~~029	20,~~826~~693	5,~~789~~752	$~~35.07~~34.85	$~~31.02~~30.82
Oil Well Sites (GOR < 300)	7,841	6,~~413~~400	2,~~637~~632	~~733~~732	$6.~~57~~55	$6.~~05~~04
Low Production Well Sites	**16,132**	**~~13,493~~11,776**	**~~6,518~~5,671**	**1,~~812~~576**	**$~~13.82~~12.06**	**$~~12.55~~10.96**
Gas Well Sites	1,734	1,~~483~~347	1,~~425~~294	~~396~~360	$1.~~52~~38	$1.~~24~~13
Oil Well Sites (GOR > 300)	5,186	~~4,369~~3,503	~~2,299~~1,844	~~639~~512	$~~4.47~~3.59	$~~4.03~~3.23
Oil Well Sites (GOR < 300)	9,212	~~7,641~~6,926	2,~~794~~533	~~777~~704	$7.~~83~~09	$~~7.28~~6.60
Well Sites Total	**71,466**	**~~61,403~~58,170**	**~~38,552~~36,049**	**10,~~717~~021**	**$~~62.88~~59.57**	**$~~52.55.37~~**
Gathering & Boosting	1,696	1,696	23,841	6,627	$31.41	$26.76
Transmission	288	288	4,653	129	$5.26	$4.45
Storage	16	16	912	25	$0.49	$0.33
Compressor Stations Total	**2,000**	**2,000**	**29,406**	**6,781**	**$37.15**	**$31.54**

Table A1-1e. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2023						
Non-Low Production Well Sites	**63,334**	**~~54,836~~53,101**	**~~36,667~~34,771**	**~~10,192~~9,665**	**$~~56.165~~4.38**	**$~~48.764~~7.37**
Gas Well Sites	9,720	~~8,297~~6,827	~~9,811~~8,073	2,~~727~~244	$~~8.50~~6.99	$~~6.52~~5.36
Oil Well Sites (GOR > 300)	44,639	~~39,199~~38,949	23,~~837~~685	6,~~626~~584	$~~40.14~~39.89	$35.~~33~~11
Oil Well Sites (GOR < 300)	8,975	7,~~340~~325	3,~~019~~013	~~839~~837	$7.~~52~~50	$6.~~91~~89
Low Production Well Sites	**18,464**	**~~15,445~~13,480**	**~~7,460~~6,490**	**~~2,073~~1,805**	**$~~15.82~~13.80**	**$~~14.31~~12.50**
Gas Well Sites	1,984	1,~~698~~542	1,~~631~~481	~~453~~412	$1.~~74~~58	$1.~~41~~28
Oil Well Sites (GOR > 300)	5,936	~~5,001~~4,010	2,~~631~~110	~~731~~587	$~~5.12~~4.11	$~~4.59~~3.68
Oil Well Sites (GOR < 300)	10,544	~~8,746~~7,928	~~3,198~~2,899	~~889~~806	$8.~~96~~12	$~~8.31~~7.53
Well Sites Total	**81,798**	**~~70,281~~66,581**	**~~44,127~~41,261**	**~~12,265~~11,470**	**$~~71.97~~68.18**	**$~~63.07~~59.86**
Gathering & Boosting	1,908	1,908	26,821	7,456	$35.33	$29.92
Transmission	324	324	5,235	145	$5.92	$4.97
Storage	18	18	1,026	28	$0.55	$0.36
Compressor Stations Total	**2,250**	**2,250**	**33,082**	**7,629**	**$41.80**	**$35.26**

Table A1-1f. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2024						
Non-Low Production Well Sites	**71,459**	**~~61,870~~59,913**	**~~41,370~~39,231**	**~~11,500~~10,905**	**$~~63~~61.36**	**$~~54.78~~53.22**
Gas Well Sites	10,967	~~9,361~~7,703	~~11,069~~9,109	~~3,077~~2,532	$~~9.59~~7.89	$~~7.29~~6.00
Oil Well Sites (GOR > 300)	50,366	~~44,227~~43,945	26,~~895~~723	7,~~476~~428	$45.~~29~~00	$39.~~71~~46
Oil Well Sites (GOR < 300)	10,126	8,~~282~~265	3,~~406~~399	~~947~~945	$8.~~48~~46	$7.~~77~~76
Low Production Well Sites	**20,833**	**~~17,427~~15,209**	**~~8,417~~7,324**	**2,~~339~~036**	**$~~17.85~~15.58**	**$~~16.10~~14.06**
Gas Well Sites	2,239	1,~~916~~740	1,~~840~~672	~~511~~465	$1.~~96~~78	$1.~~58~~44
Oil Well Sites (GOR > 300)	6,698	~~5,643~~4,524	2,~~969~~381	~~825~~662	$~~5.78~~4.63	$~~5.16~~4.14
Oil Well Sites (GOR < 300)	11,896	~~9,868~~8,945	3,~~608~~271	~~1,003~~909	$~~10.11~~9.16	$~~9.36~~8.48
Well Sites Total	**92,292**	**~~79,297~~75,122**	**~~49,787~~46,555**	**~~13,839~~12,941**	**$~~81.20~~76.93**	**$~~70.88~~67.27**
Gathering & Boosting	2,120	2,120	29,801	8,284	$39.26	$33.07
Transmission	360	360	5,816	161	$6.58	$5.50
Storage	20	20	1,140	32	$0.61	$0.40
Compressor Stations Total	**2,500**	**2,500**	**36,757**	**8,477**	**$46.44**	**$38.97**

Table A1-1g. Nationwide Emission and Cost Analysis for Regulatory Option 1a – Annual OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2025						
Non-Low Production Well Sites	**79,616**	**~~68,933~~66,752**	**~~46,093~~43,708**	**12,~~812~~150**	**$~~70.59~~68.36**	**$~~60.71~~58.99**
Gas Well Sites	12,219	~~10,430~~8,583	~~12,333~~10,148	~~3,428~~2,821	$~~10.68~~8.79	$~~8.04~~6.61
Oil Well Sites (GOR > 300)	56,115	~~49,276~~48,961	29,~~965~~773	8,~~329~~276	$50.~~46~~14	$~~44.04~~43.76
Oil Well Sites (GOR < 300)	11,282	9,~~227~~208	3,~~795~~787	1,~~055~~053	$9.~~45~~43	$8.~~64~~62
Low Production Well Sites	**23,210**	**~~19,416~~16,946**	**~~9,378~~8,158**	**2,~~608~~268**	**$~~19.88~~17.35**	**$~~17.87~~15.60**
Gas Well Sites	2,494	~~2,134~~1,939	~~2,050~~1,862	~~570~~518	$~~2.19~~1.99	$1.~~75~~59
Oil Well Sites (GOR > 300)	7,462	~~6,287~~5,041	~~3,308~~2,652	~~920~~737	$~~6.44~~5.16	$~~5.73~~4.59
Oil Well Sites (GOR < 300)	13,254	~~10,995~~9,966	~~4,020~~3,644	1,~~118~~013	$~~11.26~~10.21	$~~10.40~~9.42
Well Sites Total	**102,826**	**~~88,349~~83,698**	**~~55,471~~51,866**	**~~15,420~~14,418**	**$~~90.47~~85.71**	**$~~78.58~~74.59**
Gathering & Boosting	2,332	2,332	32,781	9,112	$43.18	$36.15
Transmission	396	396	6,398	177	$7.23	$6.01
Storage	22	22	1,253	35	$0.67	$0.43
Compressor Stations Total	**2,750**	**2,750**	**40,432**	**9,324**	**$51.08**	**$42.59**

Table A1-2a. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2019						
Non-Low Production Well Sites	**32,720**	**~~28,329~~27,433**	**~~14,207~~13,472**	**3,~~949~~745**	**$21.~~76~~07**	**~~$19.21~~18.66**
Gas Well Sites	5,022	~~4,286~~3,527	3,~~801~~128	~~1,057~~870	~~$3.29~~2.71	$2.~~61~~15
Oil Well Sites (GOR > 300)	23,062	20,~~251~~122	9,~~236~~177	2,~~567~~551	$15.~~55~~45	$13.~~90~~81
Oil Well Sites (GOR < 300)	4,636	3,~~792~~784	1,~~170~~167	~~325~~324	$2.91	$2.70
Low Production Well Sites	**9,539**	**~~7,979~~6,965**	**2,~~891~~515**	**~~803~~699**	**~~$6.13~~5.35**	**~~$5.61~~4.90**
Gas Well Sites	1,025	~~877~~797	~~632~~574	~~176~~160	$0.~~67~~61	$0.~~56~~51
Oil Well Sites (GOR > 300)	3,067	2,~~584~~072	~~1,020~~818	~~283~~227	$1.~~98~~59	$1.~~80~~44
Oil Well Sites (GOR < 300)	5,447	4,~~518~~096	1,~~239~~123	~~344~~312	$3.~~47~~15	~~$3.25~~2.94
Well Sites Total	**42,259**	**~~36,308~~34,398**	**~~17,098~~15,987**	**4,~~752~~444**	**~~$27.89~~26.42**	**~~$24.83~~23.56**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-2b. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2020						
Non-Low Production Well Sites	**39,993**	**~~34,626~~33,531**	**~~17,365~~16,467**	**4,~~827~~578**	**$~~26.59~~25.75**	**$~~23.21~~22.55**
Gas Well Sites	6,138	~~5,239~~4,311	~~4,646~~3,823	1,~~292~~063	$~~4.02~~3.31	$~~3.12~~2.57
Oil Well Sites (GOR > 300)	28,188	24,~~752~~594	11,~~289~~217	3,~~138~~118	$~~19.01~~18.89	$16.~~81~~71
Oil Well Sites (GOR < 300)	5,667	4,~~635~~626	1,~~430~~427	397	$3.~~56~~55	$3.~~28~~27
Low Production Well Sites	**11,659**	**~~9,753~~8,512**	**3,~~533~~074**	**~~982~~855**	**$~~7.49~~6.54**	**$~~6.80~~5.94**
Gas Well Sites	1,253	~~1,072~~974	~~772~~702	~~215~~195	$0.~~82~~75	$0.~~67~~61
Oil Well Sites (GOR > 300)	3,748	~~3,158~~2,532	~~1,246~~999	~~346~~278	$~~2.43~~1.94	$~~2.18~~1.75
Oil Well Sites (GOR < 300)	6,658	5,~~523~~006	1,~~515~~373	~~421~~382	$~~4.24~~3.84	$3.~~95~~58
Well Sites Total	**51,652**	**~~44,379~~42,043**	**~~20,898~~19,541**	**5,~~809~~433**	**$~~34.09~~32.29**	**$~~30.02~~28.49**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-2c. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2021						
Non-Low Production Well Sites	**47,537**	**~~41,158~~39,857**	**~~20,641~~19,574**	**5,~~737~~440**	**$~~31~~30.61**	**$~~27.63~~26.83**
Gas Well Sites	7,296	~~6,227~~5,125	~~5,523~~4,545	1,~~535~~263	$~~4.78~~3.94	$3.~~72~~06
Oil Well Sites (GOR > 300)	33,505	29,~~422~~234	13,~~419~~333	3,~~730~~706	$22.~~60~~45	$~~20.01~~19.88
Oil Well Sites (GOR < 300)	6,736	5,~~509~~498	1,~~699~~696	~~472~~471	$4.~~23~~22	$3.90
Low Production Well Sites	**13,858**	**~~11,593~~10,118**	**~~4,199~~3,654**	**1,~~167~~016**	**$~~8.90~~7.77**	**$~~8.09~~7.07**
Gas Well Sites	1,489	1,~~274~~158	~~918~~834	~~255~~232	$0.~~98~~89	$0.~~80~~73
Oil Well Sites (GOR > 300)	4,455	3,~~754~~010	1,~~481~~188	~~412~~330	$2.~~88~~31	$2.~~60~~08
Oil Well Sites (GOR < 300)	7,914	~~6,565~~5,950	1,~~800~~632	~~500~~454	$~~5.04~~4.57	$4.~~69~~26
Well Sites Total	**61,395**	**~~52,751~~49,975**	**~~24,840~~23,228**	**6,~~904~~456**	**$~~40.52~~38.38**	**$~~35.72~~33.90**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-2d. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2022						
Non-Low Production Well Sites	**55,334**	**~~47,910~~46,394**	**~~24,025~~22,784**	**6,~~679~~333**	**$~~36.80~~35.63**	**$~~32.12~~31.20**
Gas Well Sites	8,492	~~7,249~~5,965	~~6,428~~5,290	1,~~787~~470	$~~5.57~~4.58	$~~4.32~~3.55
Oil Well Sites (GOR > 300)	39,001	34,~~248~~029	15,~~619~~520	4,~~342~~314	$26.~~30~~14	$23.~~26~~11
Oil Well Sites (GOR < 300)	7,841	6,~~413~~400	1,~~978~~974	~~550~~549	$4.~~93~~92	$4.~~54~~53
Low Production Well Sites	**16,132**	**~~13,493~~11,776**	**4,~~889~~253**	**1,~~359~~182**	**$~~10.36~~9.05**	**$~~9.41~~8.22**
Gas Well Sites	1,734	1,~~483~~347	~~1,069~~971	~~297~~270	$1.~~14~~03	$0.~~93~~85
Oil Well Sites (GOR > 300)	5,186	~~4,369~~3,503	1,~~724~~383	~~479~~384	$~~3.36~~2.69	$~~3.02~~2.42
Oil Well Sites (GOR < 300)	9,212	~~7,641~~6,926	~~2,096~~1,899	~~583~~528	$5.~~87~~32	$~~5.46~~4.95
Well Sites Total	**71,466**	**~~61,403~~58,170**	**~~28,914~~27,037**	**~~8,038~~7,515**	**$~~47.16~~44.68**	**$~~39.41~~39.53**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

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Table A1-2e. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2023						
Non-Low Production Well Sites	**63,334**	**~~54,836~~53,101**	**~~27,500~~26,079**	**7,~~644~~249**	**$~~42.12~~40.78**	**$~~36.57~~35.53**
Gas Well Sites	9,720	~~8,297~~6,827	~~7,358~~6,055	~~2,045~~1,683	$~~6.37~~5.24	$4.~~89~~02
Oil Well Sites (GOR >300)	44,639	~~39,199~~38,949	17,~~878~~764	4,~~970~~938	$~~30.11~~29.91	$26.~~50~~33
Oil Well Sites (GOR < 300)	8,975	7,~~340~~325	2,~~264~~260	~~629~~628	$5.~~64~~63	$5.~~18~~17
Low Production Well Sites	**18,464**	**~~15,445~~13,480**	**~~5,596~~4,868**	**1,~~556~~353**	**$~~11.86~~10.35**	**$~~10.73~~9.37**
Gas Well Sites	1,984	1,~~698~~542	1,~~223~~111	~~340~~309	$1.~~30~~18	$~~1.06~~0.96
Oil Well Sites (GOR > 300)	5,936	~~5,001~~4,010	1,~~974~~583	~~549~~440	$3.~~84~~08	$~~3.44~~2.76
Oil Well Sites (GOR < 300)	10,544	~~8,746~~7,928	2,~~399~~174	~~667~~604	$6.~~72~~09	$~~6.23~~5.65
Well Sites Total	**81,798**	**~~70,281~~66,581**	**~~33,096~~30,947**	**~~9,200~~8,602**	**$~~53.98~~51.14**	**$~~47.30~~44.90**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

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Table A1-2f. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2024						
Non-Low Production Well Sites	**71,459**	**~~61,870~~59,913**	**~~31,027~~29,422**	**8,~~625~~179**	**$~~47.52~~46.02**	**$~~41.08~~39.91**
Gas Well Sites	10,967	~~9,361~~7,703	~~8,302~~6,831	~~2,308~~1,899	$~~7.19~~5.92	$~~5.47~~4.50
Oil Well Sites (GOR > 300)	50,366	~~44,227~~43,945	20,~~171~~042	5,~~607~~571	$33.~~97~~75	$29.~~78~~59
Oil Well Sites (GOR <300)	10,126	8,~~282~~265	2,~~554~~549	~~710~~709	$6.~~36~~35	$5.~~83~~82
Low Production Well Sites	**20,833**	**~~17,427~~15,209**	**~~6,313~~5,493**	**1,~~755~~526**	**$~~13.38~~11.68**	**$~~12.07~~10.54**
Gas Well Sites	2,239	1,~~916~~740	1,~~380~~254	~~384~~348	$1.~~47~~34	$1.~~18~~08
Oil Well Sites (GOR > 300)	6,698	~~5,643~~4,524	~~2,227~~1,786	~~619~~496	$~~4.33~~3.47	$3.~~87~~10
Oil Well Sites (GOR < 300)	11,896	~~9,868~~8,945	2,~~706~~453	~~752~~682	$~~7.58~~6.87	$~~7.02~~6.36
Well Sites Total	**92,292**	**~~79,297~~75,122**	**~~37,340~~34,915**	**~~10,380~~9,705**	**$~~60.90~~57.70**	**$~~53.16~~50.45**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

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Table A1-2g. Nationwide Emission and Cost Analysis for Regulatory Option 1b – Stepped OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2025						
Non-Low Production Well Sites	**79,616**	**~~68,933~~66,752**	**~~34,569~~32,781**	**9,~~609~~113**	**$~~52.94~~51.27**	**$~~45.53~~44.24**
Gas Well Sites	12,219	~~10,430~~8,583	~~9,249~~7,611	2,~~571~~116	$~~8.01~~6.59	$~~6.03~~4.96
Oil Well Sites (GOR >300)	56,115	~~49,276~~48,961	22,~~474~~330	6,~~247~~207	$37.~~85~~60	$~~33.03~~32.82
Oil Well Sites (GOR < 300)	11,282	9,~~227~~208	2,~~846~~840	~~791~~790	$7.~~09~~07	$6.~~48~~46
Low Production Well Sites	**23,210**	**~~19,416~~16,946**	**~~7,034~~6,119**	**1,~~955~~701**	**$~~14.91~~13.01**	**$~~13.40~~11.70**
Gas Well Sites	2,494	~~2,134~~1,939	1,~~538~~397	~~427~~388	$1.~~64~~49	$1.~~31~~19
Oil Well Sites (GOR > 300)	7,462	~~6,287~~5,041	~~2,481~~1,989	~~690~~553	$~~4.83~~3.87	$~~4.30~~3.45
Oil Well Sites (GOR < 300)	13,254	~~10,995~~9,966	~~3,015~~2,733	~~838~~760	$~~8.44~~7.65	$7.~~80~~07
Well Sites Total	**102,826**	**~~88,349~~83,698**	**~~41,603~~38,900**	**~~11,564~~10,814**	**$~~67.86~~64.28**	**$~~58.93~~55.94**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

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Table A1-3a. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2019						
Non-Low Production Well Sites	**32,720**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	5,022	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	23,062	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	4,636	0	0	0	$0.00	$0.00
Low Production Well Sites	**9,539**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	1,025	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	3,067	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	5,447	0	0	0	$0.00	$0.00
Well Sites Total	**42,259**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,060	1,060	7,450	2,071	$13.09	$11.75
Transmission	180	180	1,454	40	$2.19	$1.96
Storage	10	10	285	8	$0.20	$0.16
Compressor Stations Total	**1,250**	**1,250**	**9,189**	**2,119**	**$15.48**	**$13.87**

Table A1-3b. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2020						
Non-Low Production Well Sites	**39,993**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	6,138	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	28,188	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	5,667	0	0	0	$0.00	$0.00
Low Production Well Sites	**11,659**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	1,253	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	3,748	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	6,658	0	0	0	$0.00	$0.00
Well Sites Total	**51,652**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,272	1,272	8,940	2,485	$15.70	$13.96
Transmission	216	216	1,745	48	$2.63	$2.33
Storage	12	12	342	9	$0.24	$0.18
Compressor Stations Total	**1,500**	**1,500**	**11,027**	**2,542**	**$18.58**	**$16.47**

Table A1-3c. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2021						
Non-Low Production Well Sites	**47,537**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	7,296	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	33,505	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	6,736	0	0	0	$0.00	$0.00
Low Production Well Sites	**13,858**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	1,489	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	4,455	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	7,914	0	0	0	$0.00	$0.00
Well Sites Total	**61,395**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,484	1,484	10,430	2,899	$18.32	$16.31
Transmission	252	252	2,036	56	$3.07	$2.72
Storage	14	14	399	11	$0.28	$0.21
Compressor Stations Total	**1,750**	**1,750**	**12,865**	**2,966**	**$21.67**	**$19.24**

Table A1-3d. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2022						
Non-Low Production Well Sites	**55,334**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	8,492	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	39,001	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	7,841	0	0	0	$0.00	$0.00
Low Production Well Sites	**16,132**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	1,734	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	5,186	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	9,212	0	0	0	$0.00	$0.00
Well Sites Total	**71,466**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,696	1,696	11,920	3,314	$20.94	$18.62
Transmission	288	288	2,327	64	$3.51	$3.10
Storage	16	16	456	13	$0.32	$0.24
Compressor Stations Total	**2,000**	**2,000**	**14,703**	**3,391**	**$24.77**	**$21.96**

Table A1-3e. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2023						
Non-Low Production Well Sites	**63,334**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	9,720	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	44,639	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	8,975	0	0	0	$0.00	$0.00
Low Production Well Sites	**18,464**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	1,984	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	5,936	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	10,544	0	0	0	$0.00	$0.00
Well Sites Total	**81,798**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,908	1,908	13,410	3,728	$23.55	$20.85
Transmission	324	324	2,617	73	$3.95	$3.47
Storage	18	18	513	14	$0.36	$0.27
Compressor Stations Total	**2,250**	**2,250**	**16,540**	**3,815**	**$27.86**	**$24.60**

Table A1-3f. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2024						
Non-Low Production Well Sites	**71,459**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	10,967	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	50,366	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	10,126	0	0	0	$0.00	$0.00
Low Production Well Sites	**20,833**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	2,239	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	6,698	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	11,896	0	0	0	$0.00	$0.00
Well Sites Total	**92,292**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	2,120	2,120	14,900	4,142	$26.17	$23.08
Transmission	360	360	2,908	81	$4.38	$3.84
Storage	20	20	570	16	$0.41	$0.30
Compressor Stations Total	**2,500**	**2,500**	**18,378**	**4,239**	**$30.96**	**$27.22**

Table A1-3g. Nationwide Emission and Cost Analysis for Regulatory Option 1c – Semiannual OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2025						
Non-Low Production Well Sites	**79,616**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	12,219	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	56,115	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	11,282	0	0	0	$0.00	$0.00
Low Production Well Sites	**23,210**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	2,494	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	7,462	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	13,254	0	0	0	$0.00	$0.00
Well Sites Total	**102,826**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	2,332	2,332	16,390	4,556	$28.79	$25.27
Transmission	396	396	3,199	89	$4.82	$4.21
Storage	22	22	627	17	$0.45	$0.33
Compressor Stations Total	**2,750**	**2,750**	**20,216**	**4,662**	**$34.06**	**$29.81**

Table A1-4a. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2019						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Well Sites Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,060	0	0	0	$0.00	$0.00
Transmission	180	0	0	0	$0.00	$0.00
Storage	10	0	0	0	$0.00	$0.00
Compressor Stations Total	**1,250**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-4b. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2020						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Well Sites Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,272	0	0	0	$0.00	$0.00
Transmission	216	0	0	0	$0.00	$0.00
Storage	12	0	0	0	$0.00	$0.00
Compressor Stations Total	**1,500**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-4c. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2021						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Well Sites Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,484	0	0	0	$0.00	$0.00
Transmission	252	0	0	0	$0.00	$0.00
Storage	14	0	0	0	$0.00	$0.00
Compressor Stations Total	**1,750**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-4d. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2022						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Well Sites Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,696	0	0	0	$0.00	$0.00
Transmission	288	0	0	0	$0.00	$0.00
Storage	16	0	0	0	$0.00	$0.00
Compressor Stations Total	**2,000**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-4e. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2023						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Well Sites Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	1,908	0	0	0	$0.00	$0.00
Transmission	324	0	0	0	$0.00	$0.00
Storage	18	0	0	0	$0.00	$0.00
Compressor Stations Total	**2,250**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-4f. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2024						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Well Sites Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	2,120	0	0	0	$0.00	$0.00
Transmission	360	0	0	0	$0.00	$0.00
Storage	20	0	0	0	$0.00	$0.00
Compressor Stations Total	**2,500**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-4g. Nationwide Emission and Cost Analysis for Regulatory Option 1d – Quarterly OGI Monitoring and Repair

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Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2025						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Well Sites Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gathering & Boosting	2,332	0	0	0	$0.00	$0.00
Transmission	396	0	0	0	$0.00	$0.00
Storage	22	0	0	0	$0.00	$0.00
Compressor Stations Total	**2,750**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-5a. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2019						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**9,539**	**6,970**	**5,030**	**1,398**	**$10.70**	**$9.80**
Gas Well Sites	1,025	797	1,148	319	$1.22	$1.02
Oil Well Sites (GOR > 300)	3,067	2,077	1,636	455	$3.18	$2.89
Oil Well Sites (GOR < 300)	5,447	4,096	2,246	624	$6.29	$5.89
Well Sites Total	**9,539**	**6,970**	**5,030**	**1,398**	**$10.70**	**$9.80**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-5b. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2020						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**11,659**	**8,518**	**6,149**	**1,709**	**$13.08**	**$11.88**
Gas Well Sites	1,253	974	1,403	390	$1.50	$1.22
Oil Well Sites (GOR > 300)	3,748	2,538	2,000	556	$3.89	$3.50
Oil Well Sites (GOR < 300)	6,658	5,006	2,746	763	$7.69	$7.16
Well Sites Total	**11,659**	**8,518**	**6,149**	**1,709**	**$13.08**	**$11.88**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-5c. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2021						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**13,858**	**10,125**	**7,310**	**2,032**	**$15.55**	**$14.14**
Gas Well Sites	1,489	1,158	1,668	464	$1.78	$1.46
Oil Well Sites (GOR > 300)	4,455	3,017	2,378	661	$4.63	$4.17
Oil Well Sites (GOR < 300)	7,914	5,950	3,264	907	$9.14	$8.51
Well Sites Total	**13,858**	**10,125**	**7,310**	**2,032**	**$15.55**	**$14.14**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-5d. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2022						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**16,132**	**11,785**	**8,509**	**2,365**	**$18.10**	**$16.44**
Gas Well Sites	1,734	1,347	1,942	540	$2.07	$1.69
Oil Well Sites (GOR > 300)	5,186	3,512	2,768	769	$5.39	$4.85
Oil Well Sites (GOR < 300)	9,212	6,926	3,799	1,056	$10.64	$9.90
Well Sites Total	**16,132**	**11,785**	**8,509**	**2,365**	**$18.10**	**$16.44**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-5e. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2023						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**18,464**	**13,490**	**9,738**	**2,708**	**$20.71**	**$18.75**
Gas Well Sites	1,984	1,542	2,222	618	$2.37	$1.92
Oil Well Sites (GOR > 300)	5,936	4,020	3,168	881	$6.16	$5.53
Oil Well Sites (GOR < 300)	10,544	7,928	4,348	1,209	$12.18	$11.30
Well Sites Total	**18,464**	**13,490**	**9,738**	**2,708**	**$20.71**	**$18.75**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-5f. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2024						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**20,833**	**15,220**	**10,987**	**3,054**	**$23.37**	**$21.09**
Gas Well Sites	2,239	1,740	2,507	697	$2.67	$2.15
Oil Well Sites (GOR > 300)	6,698	4,535	3,574	993	$6.96	$6.21
Oil Well Sites (GOR < 300)	11,896	8,945	4,906	1,364	$13.74	$12.72
Well Sites Total	**20,833**	**15,220**	**10,987**	**3,054**	**$23.37**	**$21.09**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

Table A1-5g. Nationwide Emission and Cost Analysis for Regulatory Option 1e – Biennial OGI Monitoring and Repair

Source/Facility Type	Number of Sources Subject to NSPS	Number of Sources Change Control as a Result of this Reconsideration	Nationwide Emission Increase (tpy)		Total Reduction in Nationwide Annualized Costs (million $/year at 7%)	
			Methane	VOC	without savings	with savings
Project Year 2025						
Non-Low Production Well Sites	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**
Gas Well Sites	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR > 300)	0	0	0	0	$0.00	$0.00
Oil Well Sites (GOR < 300)	0	0	0	0	$0.00	$0.00
Low Production Well Sites	**23,210**	**16,958**	**12,242**	**3,403**	**$26.04**	**$23.41**
Gas Well Sites	2,494	1,939	2,794	777	$2.98	$2.38
Oil Well Sites (GOR > 300)	7,462	5,053	3,982	1,107	$7.75	$6.90
Oil Well Sites (GOR < 300)	13,254	9,966	5,466	1,519	$15.31	$14.14
Well Sites Total	**23,210**	**16,958**	**12,242**	**3,403**	**$26.04**	**$23.41**
Gathering & Boosting	0	0	0	0	$0.00	$0.00
Transmission	0	0	0	0	$0.00	$0.00
Storage	0	0	0	0	$0.00	$0.00
Compressor Stations Total	**0**	**0**	**0**	**0**	**$0.00**	**$0.00**

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Attachment 2

Supporting Information for Certifications

Table A2-1a. Estimated Count of Affected Facilities Requiring Certifications for 2019

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	9,597
Total	13,417

Table A2-1b. Estimated Count of Affected Facilities Requiring Certifications for 2020

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	10,375
Total	14,195

Table A2-1c. Estimated Count of Affected Facilities Requiring Certifications for 2021

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	10,762
Total	14,582

Table A2-1d. Estimated Count of Affected Facilities Requiring Certifications for 2022

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	11,123
Total	14,943

Table A2-1e. Estimated Count of Affected Facilities Requiring Certifications for 2023

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	10,413
Total	15,233

Table A2-1f. Estimated Count of Affected Facilities Requiring Certifications for 2024

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	11,591
Total	15,411

Table A2-1g. Estimated Count of Affected Facilities Requiring Certifications for 2025

Year	Count of Certifications Under NSPS
Pneumatic Pumps	3,794
Centrifugal Compressors	18
Reciprocating Compressors	8
Storage Vessels	11,026
Total	15,456

Table A2-2a. Summary of National Level Impact for PE Certification Alternatives in 2019

Certification Costs - 2019	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	13,417	$7,334,666
Cost Estimate for Proposed Reconsideration	13,417	$4,804,578
Reduced Burden of Proposed In-House Engineer Certification	13,417	$2,530,088

Table A2-2b. Summary of National Level Impact for PE Certification Alternatives in 2020

Certification Costs - 2020	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	14,195	$7,759,589
Cost Estimate for Proposed Reconsideration	14,195	$5,082,924
Reduced Burden of Proposed In-House Engineer Certification	14,195	$2,676,665

Table A2-2c. Summary of National Level Impact for PE Certification Alternatives in 2021

Certification Costs - 2021	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	14,582	$7,971,475
Cost Estimate for Proposed Reconsideration	14,582	$5,221,720
Reduced Burden of Proposed In-House Engineer Certification	14,582	$2,749,755

Table A2-2d. Summary of National Level Impact for PE Certification Alternatives in 2022

Certification Costs - 2022	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	14,943	$8,168,556
Cost Estimate for Proposed Reconsideration	14,943	$5,350,818
Reduced Burden of Proposed In-House Engineer Certification	14,943	$2,817,738

Table A2-2e. Summary of National Level Impact for PE Certification Alternatives in 2023

Certification Costs - 2023	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	15,233	$8,327,068
Cost Estimate for Proposed Reconsideration	15,233	$5,454,652
Reduced Burden of Proposed In-House Engineer Certification	15,233	$2,872,417

Table A2-2f. Summary of National Level Impact for PE Certification Alternatives in 2024

Certification Costs - 2024	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	15,411	$8,424,421
Cost Estimate for Proposed Reconsideration	15,411	$5,518,422
Reduced Burden of Proposed In-House Engineer Certification	15,411	$2,905,998

Table A2-2g. Summary of National Level Impact for PE Certification Alternatives in 2025

Certification Costs - 2025	Number of Sources	Equipment Certification Cost ($)
Revised Cost Estimate for 2016 NSPS OOOOa	15,456	$8,449,280
Cost Estimate for Proposed Reconsideration	15,456	$5,534,706
Reduced Burden of Proposed In-House Engineer Certification	15,456	$2,914,573

Regulatory Impact Analysis for the Proposed Reconsideration of the Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources

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EPA-452/R-18-001
May 2018

Regulatory Impact Analysis for the Proposed Reconsideration of the Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources

U.S. Environmental Protection Agency
Office of Air Quality Planning and Standards
Health and Environmental Impacts Division
Research Triangle Park, NC

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1 EXECUTIVE SUMMARY

1.1 Background

The action analyzed in this regulatory impact analysis (RIA) accompanies the proposed reconsideration of certain aspects of the Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources published in the Federal Register on June 3, 2016 ("2016 NSPS OOOOa"). In the 2016 NSPS OOOOa, new source performance standards (NSPS) were established to reduce greenhouse gas emissions and volatile organic compound (VOC) emissions from the oil and natural gas sector. The emission sources covered in the rule include hydraulically fractured oil and gas well completions and fugitive emissions from well sites and compressor stations, and pneumatic pumps. The EPA has granted reconsideration of three requirements: the fugitive emissions requirements, well site pneumatic pump standards, and requirements for certification of closed vent system design and capacity by a professional engineer. In addition, the EPA is reconsidering additional issues to streamline implementation and cost-effectiveness of compliance, including clarifying definitions.

For purposes of this RIA, we focus on the proposed amendments that result in quantifiable cost or emissions changes compared to an updated baseline. These provisions are those related to the fugitive emissions requirements and certification by a professional engineer. For details on the other provisions included in this proposed reconsideration that are not analyzed in this RIA, see the preamble to the Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration, found in the docket.[1] We do not analyze all provisions included in the preamble because we either do not have the data to do so (for example, we do not have the data to analyze how the proposed exemption for fugitive components including and downstream of the custody meter assembly will increase emissions), or because we do not think the provision will lead to meaningful cost savings or emission changes (for example, clarifying the circumstances for pneumatic pump infeasibility determinations).

One of the requirements the EPA is proposing to amend is monitoring frequency for fugitive emissions requirements at certain well sites and compressor stations. Under the proposed

[1] Found on http://www.regulations.gov under Docket ID No. EPA-HQ-OAR-2017-0483

amendments, the monitoring frequency for a specific well site or compressor station will depend on the production of the well site or on the location of the well site or compressor station. In the 2016 NSPS OOOOa, all NSPS affected well sites are required to perform semiannual monitoring, and all NSPS affected compressor stations are required to perform quarterly monitoring. On March 12, 2018, the EPA finalized a package containing amendments to the 2016 NSPS OOOOa ("Amendments package") to address immediate concerns regarding implementation challenges related to the reliability of emission monitoring equipment during extended periods of extreme cold temperatures on the Alaskan North Slope.[2] These amendments reduce monitoring frequency at NSPS affected well sites on the Alaskan North Slope from semiannual to annual. In this reconsideration, the EPA is proposing to change monitoring frequency at NSPS affected low production well sites (well sites with less than 15 barrels of oil equivalent (BOE) per well per day) to annual, and proposing to change monitoring frequency at all other NSPS affected well sites to semiannual for two years and then reducing the frequency to annual. The EPA is also proposing to reduce monitoring frequency at NSPS affected compressor stations on the Alaskan North Slope from quarterly to annual, and retain the quarterly monitoring requirements at all other compressor stations.

In the 2016 NSPS OOOOa, the EPA finalized a requirement for closed vent systems (CVS) on NSPS affected storage vessels, pneumatic pumps, reciprocating compressors and centrifugal compressors to be certified by a professional engineer, if applicable. In addition, the EPA finalized a requirement that a "qualified professional engineer" would have to certify technical infeasibility for sources claiming that routing emissions from a pneumatic pump at a well site to a control device is technically infeasible. The costs for those certifications by a professional engineer were not considered in the 2016 NSPS OOOOa regulatory impact analysis (2016 NSPS RIA).[3] This RIA estimates those costs in the updated baseline and the impact of proposing to change the requirement to allow certification by an in-house engineer as well.

This analysis estimates the impacts of the proposed changes as compared to an updated baseline, explained in section 1.2, for the analysis years 2019 through 2025. All monetized impacts of these amendments are presented in 2016 dollars. This analysis also includes a

[2] 83 FR 10628

[3] Found under Docket ID No. EPA-HQ-OAR-2010-0505, and at https://www3.epa.gov/ttn/ecas/docs/ria/oilgas_ria_nsps_final_2016-05.pdf

presentation of the impacts in a present value (PV) framework. All sources that are affected by the 2016 NSPS OOOOa, starting at the promulgation of the 2016 NSPS OOOOa, are called "NSPS affected sources." The subset of these sources that experience a change in their requirements due to this proposed action, are called "reconsideration affected sources." The universe of reconsideration affected sources varies across the options being considered. This will be explained more in section 1.3, below.

1.2 Summary of Updates from the Final 2016 NSPS RIA

This section summarizes the updates made to data, assumptions, source counts, projections and state and local regulations that have been revised or promulgated since the promulgation of the 2016 NSPS OOOOa that affect the impacts of the proposed actions quantified in this RIA. These updates were combined with unchanged assumptions and methods from the 2016 NSPS RIA to estimate an updated, 2018 baseline. This 2018 baseline represents the current state of the industry. The cost and emission impacts estimated as a result of the three options analyzed in this RIA are compared to this updated 2018 baseline. The updates and revisions that affect the estimated impacts include:

- **Annual Energy Outlook:** In the 2016 NSPS OOOOa, we used the 2015 Annual Energy Outlook. For the purposes of this analysis, we are using the most recent publication of the Annual Energy Outlook, published February 2018.[4] The estimates of drilling activity published in the AEO is used to estimate projections of NSPS affected sources over time, and the estimates of natural gas prices are used to estimate the value of product recovery.
- **U.S. Greenhouse Gas Inventory updates:** Since the promulgation of the 2016 NSPS OOOOa, the U.S. Greenhouse Gas Inventory (GHGI) has been updated.[5] The data from the updated GHGI was used in the projection of NSPS affected sources over time.
- **DrillingInfo:** This RIA uses a more recent version of the DrillingInfo dataset than was used for the 2016 NSPS OOOOa.[6] The DrillingInfo dataset is used to characterize oil and gas wells and completion activity in the base year. The base year is 2014 in this analysis, updated from 2012 in the 2016 NSPS RIA.
- **State and Local Regulations:** Since the promulgation of the 2016 NSPS OOOOa, additional state and local requirements affecting the oil and natural gas sector have been published, namely regulations in California and general permits in Pennsylvania. In this

[4] The 2018 AEO can be found at: https://www.eia.gov/outlooks/aeo/

[5] The updated GHGI data used is from the April 2018 release. For information on the inventory, visit https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks

[6] DrillingInfo is a private company that provides information and analysis to the energy sector. More information is available at: http://info.drillinginfo.com

analysis, we take the requirements from California, Colorado, Ohio, Pennsylvania, and Utah into account. The requirements in those states are expected to result in broadly similar overall emissions reductions, though the particular program designs in each of these states differs from the 2016 NSPS OOOOa and the reconsideration requirements. In the 2016 NSPS RIA, Wyoming's program was included as a program expected to result in broadly similar overall emissions reductions. The requirements in Wyoming were reexamined and are no longer considered to be equivalent for purposes of the RIA because they are basin specific permit requirements, and are not applicable to the entire state.[7]

- **Fugitive Emissions Requirements**: Since the promulgation of the 2016 NSPS OOOOa, the EPA has published a final package which amends the fugitive emissions monitoring and repair requirements for NSPS affected oil and natural gas well sites on the Alaskan North Slope. Fugitive emissions monitoring at those sites was required to be done semiannually under the 2016 NSPS OOOOa. The Amendments package reduces the monitoring frequency for NSPS affected well sites on the Alaskan North Slope from semiannual to annual.
- **Professional Engineer Certification**: The 2016 NSPS OOOOa requires closed vent systems and pneumatic pump technical infeasibility be certified by a professional engineer. The cost of this provision was not quantified in the 2016 NSPS RIA analysis. In this analysis, we are including the cost of the requirement for professional engineer certifications in the baseline.
- **Social Cost of Methane:** In the 2016 NSPS OOOOa, the EPA used an estimate of the global social cost of methane to monetize the climate related benefits associated with reductions in methane emissions. Since the promulgation of the 2016 NSPS OOOOa, E.O. 13783 has been signed, which directed agencies to ensure that estimates of the social cost of greenhouse gases used in economic analyses are consistent with the guidance contained in OMB Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (E.O. 13783, Section 5(c)). Thus, for this reconsideration, we are using an interim estimate of the domestic social cost of methane to estimate the forgone climate benefits resulting from the increase in methane emissions due to the proposed action.
- **Model Plants:** The model plants used to estimate the emissions from a well site, and emission reductions due to the fugitive emissions monitoring requirements, have been updated. The update includes the addition of fugitive emissions components, namely storage vessels. By adding storage vessels to the model plant, base emissions from a wellsite are estimated to be larger, and the reductions due to the monitoring and repair requirements have also increased.[8]
- **Other**: In the 2016 NSPS OOOOa, all costs and benefits were presented in 2012 dollars. In this analysis, all estimated costs are presented in 2016 dollars per Executive Order

[7] For information on additional states that were examined and why they are not considered equivalent, see the TSD and the State memo, both of which are available in the docket.
[8] For more information on the model plants, see the TSD.

(E.O.) 13771 implementation guidance.[9] In addition, in the 2016 NSPS RIA, we only presented the annualized compliance costs and the benefits resulting from emission reductions occurring in 2020 and 2025. For this analysis, we estimate the cost savings and forgone benefits resulting from changes in compliance activities and emissions occurring in each year from 2019 through 2025.[10] We also discount the annual cost savings and forgone benefits to 2016, and present total PV and equivalent annualized value (EAV) over the analysis period.

Table 1-1, below shows the number of NSPS affected facilities, methane emission reductions, VOC emission reductions and the total annualized costs including the value of product recovery, in 2020 and in 2025 for the fugitive emissions requirements of the 2016 NSPS OOOOa as estimated in the 2016 NSPS RIA, and under the 2018 updated baseline. The emission reductions presented here are the emission reductions assuming the affected sources were not performing compliance activities prior to the 2016 NSPS OOOOa. As mentioned above, the 2016 NSPS RIA estimates did not include the cost of professional engineer certification. To be consistent, the estimates presented in this table for the 2018 baseline also exclude the cost of professional engineer certification. It should be noted, however, that the assumptions used to estimate the 2018 baseline values have been updated from those used to estimate the 2016 NSPS RIA values as explained above. In addition, the 2016 NSPS OOOOa costs presented here do not match the cost estimates for the fugitive emissions requirements as presented in the 2016 NSPS RIA. This is because costs in the 2016 NSPS RIA are presented in 2012 dollars, and they have been updated to 2016 dollars in this table.

[9] Costs were adjusted to 2016 dollars using the seasonally adjusted annual Gross Domestic Product: Implicit Price Deflator released by the Federal Reserve on January 26, 2018.

[10] In this analysis, the DrillingInfo base year was updated from 2012 to 2014, therefore, the source projection estimates are based on reconsideration affected facilities established starting in 2014 and it goes through 2025.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Estimated Cost and Emission Reductions of the 2016 NSPS OOOOa Fugitive Emissions Requirements: 2016 NSPS RIA and Updated 2018 Baseline Comparison

	2016 NSPS RIA		2018 Baseline	
	2020	2025	2020	2025
Counts of NSPS Affected Fugitive Emissions Sources	94,100	192,300	44,000	87,000
Methane Emission Reductions (short tons)	169,600	346,200	120,000	240,000
VOC Emission Reductions (tons)	46,300	94,500	32,000	62,000
Total Annualized Cost, with Product Recovery (7%, millions, 2016$)	$199	$407	$115	$219

1.3 Regulatory Options Analyzed in this RIA

In this RIA, we examine the effect of the proposed actions relative to the updated 2018 baseline. The sources affected by this proposed reconsideration (termed "reconsideration affected sources" in this RIA) are a subset of the NSPS affected sources. The universe of reconsideration affected sources includes sources of the types affected by this reconsideration that are considered new or modified starting in 2019, as well as sources that were affected by the 2016 NSPS OOOOa before 2019 and are expected to change compliance activity as a result of this action. For example, a low production well site that became an NSPS affected source in 2016 is also a reconsideration affected source under Option 2, because they are expected to change compliance activities (reduce monitoring frequency from semiannual to annual). In addition, the estimates of new low production well sites starting in 2019 are also reconsideration affected sources since the proposed action is different than the 2016 NSPS OOOOa action they would be performing otherwise. However, projected new affected well sites on the Alaskan North Slope are not reconsideration affected sources under Option 2, since they are not changing compliance activities as a result of this action. The change in compliance activities (from semiannual to annual fugitive emissions monitoring frequency) at those well sites is attributed to the Amendments package. As we assume certifications only happen once, the only affected sources for the proposed certification requirements are those that become affected starting in 2019. We also examine the effect of two alternative suites of options. The universe of reconsideration affected sources is different under the different options. Table 1-2 shows the affected sources, points and controls for the 2016 NSPS OOOOa, the updated 2018 baseline and the three options that are analyzed in this RIA. The bolded entries in the table represent the

sources that are considered reconsideration affected sources under each option.[11]

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Emissions Sources and Controls Evaluated for the Regulatory Alternatives

Emissions Point	2016 NSPS OOOOa	2018 Baseline	Option 1	Option 2 (Proposed)	Option 3
Fugitive Emissions - Planning, Monitoring and Maintenance					
Natural Gas and Oil Well Sites	Semiannual	Semiannual	Semiannual	**2 Yrs. Semiannual, then Annual**	**Annual**
Low Production Well Sites (<15 BOE/day)	Semiannual	Semiannual	Semiannual	**Annual**	**Biennial**
Natural Gas and Oil Well Sites on the Alaskan North Slope	Semiannual	Annual	Annual	Annual	**Exempt**
Compressor Stations in Gathering and Boosting, Transmission and Storage	Quarterly	Quarterly	Quarterly	Quarterly	Quarterly
Compressor Stations in Gathering and Boosting, Transmission and Storage on the Alaskan North Slope*	Quarterly	Quarterly	Quarterly	**Annual**	**Exempt**
Certifications					
Closed Vent Systems on Pneumatic Pumps, Reciprocating Compressors, Centrifugal Compressors, and Storage Vessels; and Pneumatic Pump Technical Infeasibility	Professional Engineer	Professional Engineer	**In-House Engineer**	**In-House Engineer**	**In-House Engineer**

* We do not currently have the data to estimate the effects of the proposed amendments pertaining to compressors stations on the Alaskan North Slope. All other provisions presented in this table are analyzed in this RIA. Additional provisions included in the preamble are not analyzed because we either do not have the data to do so or because we do not think the provision will lead to meaningful cost savings or emission changes.

The 2016 NSPS OOOOa requires fugitive emissions survey and repair programs be performed semiannually (twice per year) at the NSPS affected newly drilled or refractured well sites, and quarterly at new or modified gathering and boosting stations and new or modified transmission and storage compressor stations. Closed vent systems and pneumatic pump technical infeasibility have to be certified by a professional engineer.

The updated 2018 baseline reflects that fugitive emissions survey and repair programs are now required to be performed only annually at NSPS affected well sites in the Alaskan North Slope (as promulgated in the final Amendments package), semiannually at all other NSPS affected newly drilled or refractured gas well sites, and quarterly at new or modified gathering

[11] The suite of regulations being proposed under Option 2 was determined to the "Best Source of Emissions Reductions" (BSER) as the source level. This analysis can be found in the TSD.

and boosting stations and new or modified transmission and storage compressor stations. Closed vent systems and pneumatic pump technical infeasibility have to be certified by a professional engineer.

Option 1 is the most stringent option considered. Under this analysis, fugitive emissions monitoring frequencies are unchanged. The certification requirement for closed vent systems and pneumatic pump technical infeasibility is changed to allow companies the option of using an in-house engineer as opposed to requiring a professional engineer. This option results in reduced regulatory burden related to the certification requirements, but is unlikely to affect realized emission reductions.[12] This option has the smallest universe of affected sources.

The proposed option, Option 2, reduces the monitoring frequency for all well sites outside of the Alaskan North Slope, and all compressor stations on the Alaskan North Slope. Low production well sites producing less than 15 barrels of oil equivalent (BOE) per day are required to perform fugitive emissions survey and repair programs annually. Well sites on the Alaskan North Slope retain the annual survey and repair requirement. All other NSPS affected well sites retain the semiannual survey and repair requirement for two years, stepping down to annual monitoring thereafter. Fugitive emissions survey and repair programs at compressor stations on the Alaskan North Slope are also reduced to annual frequency, while monitoring frequency at all other NSPS affected compressor stations remains at quarterly.[13] The certification requirement for closed vent systems and pneumatic pump technical infeasibility is changed to allow companies the option of using an in-house engineer as opposed to requiring a professional engineer. This option leads to reduced regulatory burden, as well as greater emissions compared to the 2018 baseline. The universe of reconsideration affected sources under this option is greater than that of Option 1.

Option 3 is the least stringent option considered. It exempts well sites and compressor stations on the Alaskan North Slope from all fugitive emissions monitoring and repair

[12] Emissions should not be affected by this change in certification requirements as long as the use of an in-house engineer does not result in any change in the quality of closed vent systems being certified or the number of pneumatic pump technical infeasibility determinations. We do not have any information to estimate the potential for these types of technical changes, if any, when moving from professional engineer certifications to in-house engineer certifications.

[13] For an analysis of the costs of the proposed option under alternative monitoring frequencies at compressor stations, see section 2.5.2.

requirements, and reduces the frequency at all other well sites to annual monitoring at non-low production well sites and biennial monitoring (every other year) at low production well sites. Fugitive emissions monitoring and repair frequency at compressor stations outside of the Alaskan North Slope remain at quarterly. The certification requirement is the same as in the proposed option: allows companies the choice of using an in-house engineer as opposed to requiring a professional engineer. This option leads to the largest universe of reconsideration affected sources, the largest impact on costs and benefits compared to the 2018 baseline, as well as the greatest increase in emissions.

1.4 Summary of Results

A summary of the key results of the proposed option of this RIA follow. All dollar estimates are in 2016 dollars. Also, all costs, emissions changes, and benefits are estimated relative to the updated 2018 baseline.

- **Emissions Analysis:** This proposed amendment to the 2016 NSPS OOOOa is expected to lead to an increase in emissions compared to the 2018 baseline. Methane emissions are estimated to increase by between 17,000 short tons per year (in 2019) and 41,000 short tons per year (in 2025) for a total of 200,000 short tons over 2019 through 2025. VOC emissions are expected to increase by between 4,700 tons per year and 11,000 tons per year, for a total of 56,000 tons over the same period. HAP emissions are expected to increase by between 180 and 430 tons per year, with an estimated total of 2,100 more tons of HAP emissions over 2019 through 2025 under the proposed amendments compared to the 2018 baseline.
- **Benefits Analysis:** The proposed option is expected to result in climate related dis-benefits compared to the 2018 baseline. The PV of the domestic share of forgone benefits, using an interim estimate of the domestic social cost of methane (SC-CH_4) discounting at a 7 percent rate is estimated to be $7.2 million from 2019 through 2025; the EAV is estimated to be $1.2 million per year. Using the interim SC-CH_4 estimate based on the 3 percent rate, the PV of the forgone domestic climate benefits is estimated to be $28 million; the EAV is estimated to be $4.4 million per year.
- **Compliance Cost Analysis:** The proposed option is expected to result in compliance cost savings to the affected firms compared to the 2018 baseline. The PV of these cost savings, discounted at a 7 percent rate and not including the forgone value of product recovery (about $26 million) is estimated to be about $234 million dollars. When the forgone value of product recovery is included, the PV of the cost savings is about $209 million. This is associated with an EAV of cost savings of about $41 million per year without including the forgone value of product recovery (about $4.5 million per year), or $36 million per year when the value of product recovery is included. Under a 3 percent discount rate, the PV of cost savings, accounting for the forgone value of product recovery (about $33 million) is $265 million, with an associated EAV of $41 million per

year after accounting for the forgone value of product recovery (about $5.2 million per year).

- **Energy Markets Impacts Analysis:** The 2016 NSPS RIA estimated small (less than 1 percent) impacts on energy production and markets as a result of the final regulation. The EPA expects that this deregulatory action, if finalized, would partially ameliorate the impacts estimated for the final NSPS in the 2016 NSPS RIA.
- **Distributional Impacts:** The compliance cost savings and forgone benefits presented in this analysis are not expected to be felt uniformly across the population, and may not accrue to the same individuals or communities. EPA did not conduct a quantitative assessment of the distributional impacts of the proposed reconsideration, but a qualitative discussion of the distributional aspects of the compliance cost savings and the forgone health benefits of this deregulatory action are provided in section 4.3.
- **Small Entity Impacts Analysis:** The EPA expects that this deregulatory action, if finalized as proposed, would ameliorate the impacts estimated for the final 2016 NSPS OOOOa in the 2016 NSPS RIA. We have therefore concluded that this action will relieve regulatory burden for all directly regulated small entities and that this action, if finalized as proposed, will not have a Significant Impact on a Substantial Number of Small Entities (SISNOSE).
- **Employment Impacts Analysis:** EPA expects slight reductions in labor associated with compliance-related activities relating to the proposed fugitive emissions requirements and the inspections of closed vent systems compared to the 2016 NSPS OOOOa. However, due to uncertainties associated with how the proposed reconsideration will influence the portfolio of activities associated with fugitive emissions-related requirements, the EPA is unable to provide quantitative estimates of compliance-related labor changes.

[REF _Ref508624117 \h] presents the estimated annualized costs accounting for product recovery and the emission reductions for the updated 2018 baseline, as well as the three options analyzed in this RIA for 2020 and 2025. The rest of this document details the changes estimated as a result of this reconsideration. These changes are estimated as the difference between the 2018 baseline and the option being analyzed.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Costs and Emissions Reductions of the 2016 NSPS OOOOa under the Updated 2018 Baseline and the Regulatory Alternatives Evaluated in the RIA

	Facilities Affected	Methane Emission Reductions (short tons)	VOC Emission Reductions (short tons)	Total Annualized Cost, w/ Product Recovery (7%, millions 2016$)
		2020		
2018 Baseline	58,000	120,000	32,000	$123
Option 1	58,000	120,000	32,000	$120
Option 2	58,000	102,000	26,000	$90
Option 3	58,000	94,000	24,000	$78
		2025		
2018 Baseline	102,100	240,000	62,000	$228
Option 1	102,100	240,000	62,000	$225
Option 2	102,100	200,000	51,000	$165
Option 3	102,000	180,000	46,000	$142

Table 1-4 through Table 1-6 present 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 increase in emissions compared to the 2018 baseline for all three options. These values are estimated for the universe of reconsideration affected sources under each option over the 2019 through 2025 analysis period, discounted to 2016, and are in 2016 dollars. When discussing net benefits, both here and in section 5, we modify the relevant terminology to be more consistent with traditional net benefits analysis. In the following tables, we refer to the cost savings as presented in section 2 as the "benefits" of this proposed action and the forgone benefits as presented in section 3 as the "costs" of this proposed action. The net benefits are the benefits (cost savings) minus the costs (forgone benefits). As explained in the following sections, all costs and benefits outlined in this RIA are estimated as the change from the updated baseline.

As can be seen in Table 1-4 through Table 1-6, Option 1 results in the smallest estimated impact on costs and emissions, and Option 3 results in the largest estimated impacts.[14] It should

[14] Option 1 is unlikely to result in any changes in emissions, because it does not affect fugitive emissions requirements. Emissions should not be affected by the change in certification requirements under Option 1 as long as the use of an in-house engineer does not result in any change in the quality of closed vent systems being certified or the number of pneumatic pump technical infeasibility determinations. We do not have any information to estimate the potential for these types of technical changes, if any, or when moving from professional engineer certifications to in-house engineer certifications.

be noted that though the net benefits increase going from Option 2 to Option 3, the emissions do as well. In addition, it should be noted that the estimated costs (forgone benefits) of Options 2 and 3 only include the monetized increase in methane emissions as a result of the option under consideration, though there are increases in VOC and HAP emissions as well. While we expect that the forgone VOC emission reductions may also degrade air quality and adversely affect health and welfare effects associated with exposure to ozone, $PM_{2.5}$, and HAP, data limitations prevent us from quantifying forgone VOC-related health benefits. This omission should not imply that these forgone benefits may not exist; rather, it reflects the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. A broader explanation of forgone benefits can be read on section 3 of this RIA.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Cost Savings, Forgone Benefits and Increase in Emissions of Option 1 Compared to the 2018 Baseline, 2019 through 2025 (millions 2016$)

	7%		3%	
	Present Value	**Equivalent Annualized Value**	**Present Value**	**Equivalent Annualized Value**
Benefits (Cost Savings)	$17	$2.9	$21	$3.3
Total Annual Cost Savings	*$17*	*$2.9*	*$21*	*$3.3*
Forgone Value of Product Recovery	*$0*	*$0*	*$0*	*$0*
Costs (Forgone Domestic Climate Benefits)[1]	$0	$0	$0	$0
Net Benefits[2]	$17	$2.9	$21	$3.3
Emissions	**Total Change**			
Methane (short tons)	0			
VOC	0			
HAP	0			
Methane (million metric tons CO2E)	0			

[1] The forgone benefits estimates are calculated using estimates of the social cost of methane (SC-CH_4). SC-CH_4 values represent only a partial accounting of domestic climate impacts from methane emissions. This option is unlikely to affect emissions, therefore there are no monetized forgone benefits as a result of this option.
[2] Estimates may not sum due to independent rounding.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Cost Savings, Forgone Benefits and Increase in Emissions of the Proposed Option 2 Compared to the 2018 Baseline, 2019 through 2025 (millions 2016$)

	7%		3%	
	Present Value	**Equivalent Annualized Value**	**Present Value**	**Equivalent Annualized Value**
Benefits (Total Cost Savings)	$209	$36	$265	$41
Total Annual Cost Savings	*$234*	*$41*	*$299*	*$47*
Forgone Value of Product Recovery	*$26*	*$4.5*	*$33*	*$5.2*
Costs (Forgone Domestic Climate Benefits)[1]	$7.2	$1.2	$28	$4.4
Net Benefits[2]	$201	$35	$237	$37
Emissions	**Total Change**			
Methane (short tons)	200,000			
VOC	56,000			
HAP	2,100			
Methane (million metric tons CO2E)	4.5			

[1] The forgone benefits estimates are calculated using estimates of the social cost of methane (SC-CH_4). SC-CH_4 values represent only a partial accounting of domestic climate impacts from methane emissions. See Section 3.3 for more discussion.

[2] Estimates may not sum due to independent rounding.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Cost Savings, Forgone Benefits and Increase in Emissions of Option 3 Compared to the 2018 Baseline, 2019 through 2025 (millions 2016$)

	7%		3%	
	Present Value	**Equivalent Annualized Value**	**Present Value**	**Equivalent Annualized Value**
Benefits (Total Cost Savings)	$282	$49	$358	$56
Total Annual Cost Savings	*$317*	*$55*	*$404*	*$63*
Forgone Value of Product Recovery	*$36*	*$6.2*	*$45*	*$7.1*
Costs (Forgone Domestic Climate Benefits)[1]	$9.9	$1.7	$39	$6.1
Net Benefits[2]	$272	$47	$319	$50
Emissions	**Total Change**			
Methane (short tons)	280,000			
VOC	77,000			
HAP	2,900			
Methane (million metric tons CO2E)	6.2			

[1] The forgone benefits estimates are calculated using estimates of the social cost of methane (SC-CH_4). SC-CH_4 values represent only a partial accounting of domestic climate impacts from methane emissions. See Section 3.3 for more discussion.

[2] Estimates may not sum due to independent rounding.

1.5 Organization of this Report

This analysis follows much of the same methods used to estimate costs of the 2016 NSPS OOOOa. The remainder of this report outlines some of that methodology, with further explanations of where the underlying data, assumptions or methods diverge, as well as the estimated results. For details on the methodology that is unchanged from the 2016 NSPS OOOOa, please see the 2016 NSPS RIA.[15] Section 2 describes the emissions and compliance cost analysis of the proposed action compared to the 2018 baseline. Section 2 also describes the cost savings compared to the 2018 baseline in a PV framework, as well as presents the associated EAV. Section 3 describes the forgone benefits of this rule compared to the 2018 baseline, including the PV and EAV over the 2019 through 2025-time frame. Section 4 describes the economic impacts expected as a result of this proposed action. Section 5 presents a comparison of forgone benefits and cost savings of this proposed reconsidered rule, as well as the net benefits compared to the updated 2018 baseline.

[15] Found at: https://www3.epa.gov/ttn/ecas/docs/ria/oilgas_ria_nsps_final_2016-05.pdf

2 COMPLIANCE COST SAVINGS AND FORGONE EMISSION REDUCTIONS

2.1 Introduction

This chapter describes the emissions and compliance cost analysis for the proposed reconsideration to the 2016 NSPS OOOOa. Incremental changes in emissions and costs as a result of this proposal are estimated with respect to a current policy baseline. Section 2.2 discusses the updates to data and the approach used in this analysis with respect to the RIA analysis for the 2016 NSPS OOOOa. Section 2.3 describes the steps in the emissions and compliance cost analysis of the requirements that are being reconsidered and presents an overview of results. Section 2.4 present detailed tables describing the impacts for each source affected by this proposed reconsideration for the analyzed options can be found at the end of the chapter. Section 2.5 presents the present value and equivalent annualized value of the cost savings. Please see the Background Technical Support Document (TSD) located at Docket ID No. EPA-HQ-OAR-2017-0483 for more detail.

2.2 Emissions Points and Pollution Controls assessed in the RIA

This RIA estimates impacts associated with reconsidered requirements for fugitive emissions requirements, and certifications of closed vent system design and technical infeasibility of routing pneumatic pump emissions to an existing control device. In addition, EPA is proposing reconsidered requirements related to pneumatic pumps and oil well completions, as well as technical corrections and clarifications, although this RIA does not quantify any changes in emissions or costs resulting from those proposed amendments. This section provides a basic description of the emissions sources and controls considered, and which aspects of the reconsideration proposals have quantified impacts in this RIA. For more detailed information on the requirements that are being reconsidered, see the Preamble.[16] For the other emission sources and controls evaluated in the 2016 NSPS OOOOa, see the 2016 NSPS RIA.[17]

[16] Found on regulations.gov under Docket ID No. EPA-HQ-OAR-2017-0483
[17] Found under Docket ID No. EPA-HQ-OAR-2010-0505, and at https://www3.epa.gov/ttn/ecas/docs/ria/oilgas_ria_nsps_final_2016-05.pdf

Fugitive Emissions Requirements: Fugitive emissions occur when connection points are not fitted properly or when seals and gaskets start to deteriorate. Pressure, changes in pressure, or mechanical stresses can also cause components or equipment to leak. Potential sources of fugitive emissions include valves, connectors, pressure relief devices, open-ended lines, flanges, closed vent systems, and thief hatches or other openings on a controlled storage vessel. These fugitive emissions do not include devices that vent as part of normal operations.

In the 2016 NSPS RIA, the EPA estimated costs and emission reductions assuming the use of a leak monitoring program based on the use of optical gas imaging (OGI) leak detection combined with leak correction. In addition, alternative frequencies for fugitive emissions surveys were considered: annual, semiannual, and quarterly. This RIA estimates the changes in impacts from reducing fugitive emissions monitoring frequency from affected oil and gas facilities.

Professional Engineer Certifications: Closed vent systems can be used to route emissions from various equipment at oil and gas facilities including storage vessels, compressors, and pneumatic pumps to control devices or processes. Closed vent systems must be designed to properly handle the particular configuration and flow rates of different facilities.

For the 2016 NSPS OOOOa, the EPA requires closed vent systems be certified by a professional engineer. In addition, the 2016 NSPS OOOOa requires that facilities claiming technically infeasibility in routing emissions from well site pneumatic pumps to an existing control device must get that technical infeasibility certified by a professional engineer. The cost impact of the professional engineer certification requirements was not evaluated in the 2016 NSPS RIA. In this analysis, the EPA evaluates the impact of the certification requirements, and the effects of allowing facilities to choose either a professional engineer or an in-house engineer to perform the required certifications.

Additional Reconsideration Topics Not Quantified in this RIA: The reconsideration preamble and proposed regulatory text includes discussion and proposals of a number of technical issues for which this analysis does not estimate impacts. These include, but are not limited to, the issues described below.[18]

- Pneumatic Pumps: The EPA is proposing changes in the circumstances for which

[18] See the Preamble for more information, at Docket ID No. EPA-HQ-OAR-2017-0483.

it may be infeasible to control emissions from well site pneumatic pumps by removing the distinctions between greenfield and non-greenfield sites. These changes are intended to better characterize the circumstances under which control may be infeasible, and thus would not necessarily lead to a change in actual emissions.

- Well Completions: The EPA is proposing changes and clarifications related to the location of separators during flowback operations, recordkeeping requirements for reduced emission completions, and the definition of flowback (e.g., to exclude screenouts, coil tubing cleanouts, and plug drill out processes). Some of these changes could increase cost savings (e.g., by lowering the burden of recordkeeping requirements) or be associated with increases in emissions relative to the 2018 baseline, but the EPA does not have sufficiently specific information to quantify these changes.
- Fugitive Emissions: In addition to the quantified issues described above, the EPA is proposing changes to fugitive emissions requirements with respect to the definitions of modification, third party equipment, and more, as well as the characterization of production levels for the purposes of well site fugitive emissions monitoring. In addition, the EPA is proposing changes to the repair of leaking fugitive emissions components that were put on a delay of repair list. Some changes may result in cost savings (e.g., aligning pneumatic pump closed vent system requirements with storage vessel closed vent system requirements), and some may result in increased emissions (e.g., exempting fugitive components downstream of the custody meter assembly), but the EPA does not have the information necessary to quantify these changes.
- Gas Processing Plants: The EPA is proposing the exempt equipment from LDAR at gas processing plants that has been in service less than 300 hours per year when the equipment is only used during emergencies, as a backup, or is only in service during startup and shutdown. This may increase costs savings and emissions due to reduced LDAR requirements, but the EPA does not have the data necessary to quantify these changes.

- Alternative Means of Emission Limitation provision: The EPA is making changes to the Alternative Means of Emission Limitation (AMEL) provision. Though the changes, as outlined in the preamble, may lead to lower costs (for example, due to streamlining regulatory efforts), we do not have any information on specifically when, or how, costs or emissions may change.

2.3 Compliance Cost Analysis

In this section, we provide an overview of the compliance cost analysis used to estimate the difference in the private expenditures to the industry when complying with the proposed reconsidered rule compared to the 2016 NSPS OOOOa, under the updated 2018 baseline. Updates to the data and analysis approach from the 2016 NSPS RIA are described in section 1.2 of this RIA. A detailed discussion of the methodology, data and assumptions used to estimate the compliance cost impacts of this reconsideration that have been updated since the 2016 NSPS RIA is presented in the TSD.[19] The methodology, data and assumptions that are not discussed here are the same as were used in the 2016 NSPS RIA, and can be found in the 2016 NSPS Final TSD for that action.[20]

The following sections describe each step in the compliance cost analysis. First, representative facilities are established for each affected source category, including baseline emissions and the control options. Second, the number of incrementally affected facilities under the 2018 baseline for each type of equipment or facility are projected, and the reconsideration affected sources are estimated. The change in national emissions and cost estimates are calculated by multiplying representative factors from the first step, by the estimated number of reconsideration affected facilities in each projection year from the second step. In addition to emissions reductions, some control options result in natural gas recovery, which can then be combusted for useful processes or sold. The change in national cost estimates include the change in estimated revenue from product recovery where applicable.

In this section, we present the effect of this proposal on costs and emissions from 2019 through 2025, under the assumption that 2019 is the first year the reconsidered requirements will

[19] Docket ID No. EPA-HQ-OAR-2017-0483
[20] Docket ID No. EPA-HQ-OAR-2010-0505-7631.

be in effect. We chose to analyze through 2025 due to limited information, as explained in section 2.3.3. In addition, in this section, we are providing analysis for 2020 and 2025, which allows the reader to draw comparisons to the 2016 NSPS RIA. Comparing the 2016 NSPS RIA results to this analysis should be done with caution. The baseline of affected sources has been updated in this analysis, as explained in section 2.3.3, and results in this RIA are presented in 2016 dollars, while the 2016 NSPS RIA results are presented in 2012 dollars.

2.3.1 Regulatory Options

For each reconsideration affected emission source, point, and control option, the TSD develops a representative facility. The characteristics of this facility include typical equipment, operating characteristics, and representative factors including baseline emissions and the costs, emissions reductions, and product recovery resulting from each control option. In this RIA, we examine three broad regulatory options. [REF _Ref445447682 \h] shows the emissions sources, points, and controls for 2016 NSPS OOOOa, the updated 2018 baseline, the proposed option and two alternative options being considered for the sources affected under this reconsideration proposal.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Emissions Sources and Controls Evaluated for the 2016 NSPS OOOOa Compared to the Proposed Reconsideration

Emissions Point	2016 NSPS OOOOa	2018 Baseline	Option 1	Option 2 (Proposed)	Option 3
Fugitive Emissions - Planning, Monitoring and Maintenance					
Natural Gas and Oil Well Sites	Semiannual	Semiannual	Semiannual	**2 Yrs. Semiannual, then Annual**	**Annual**
Low Production Well Sites (<15 BOE/day)	Semiannual	Semiannual	Semiannual	**Annual**	**Biennial**
Natural Gas and Oil Well Sites on the Alaskan North Slope	Semiannual	Annual	Annual	Annual	**Exempt**
Compressor Stations in Gathering and Boosting, Transmission and Storage	Quarterly	Quarterly	Quarterly	Quarterly	Quarterly
Compressor Stations in Gathering and Boosting, Transmission and Storage on the Alaskan North Slope*	Quarterly	Quarterly	Quarterly	**Annual**	**Exempt**
Certifications					
Closed Vent Systems on Pneumatic Pumps, Reciprocating Compressors, Centrifugal Compressors, and Storage Vessels; and Pneumatic Pumps Technical Infeasibility	Professional Engineer	Professional Engineer	**In-House Engineer**	**In-House Engineer**	**In-House Engineer**

* We do not currently have the data to estimate the effects of the proposed amendments pertaining to compressors stations on the Alaskan North Slope. All other provisions presented in this table are analyzed in this RIA. Additional

provisions included in the preamble are not analyzed because we either do not have the data to do so or because we do not think the provision will lead to meaningful cost savings or emission changes.

In addition to the requirements listed above, the 2016 NSPS OOOOa contains well completion requirements for a subset of newly completed oil wells that are hydraulically fractured or refractured. The 2016 NSPS OOOOa also requires reductions from centrifugal compressors, reciprocating compressors, and pneumatic controllers throughout the oil and natural gas source category. These requirements are not analyzed in this RIA because the proposed reconsideration does not include amendments that change the cost or emissions from those achieved under the 2016 NSPS OOOOa requirements.

2.3.2 Unit Level Cost Savings and Emission Increases

The requirements affecting fugitive emissions requirements and certifications of technical infeasibility and closed vent systems are the only sources where changes in cost and emissions resulting from proposed reconsideration requirements have been quantified. Facility level costs and emission reductions for the fugitive emission requirements for each of the model plants is in Volume 1 of the TSD. For this reconsideration, the TSD and RIA results are based on a more disaggregated set of model plants used to analyze the changes in monitoring requirements among subsets of oil and natural gas well sites than the set used in the 2016 NSPS OOOOa analysis. Whereas the previous analysis included three model plants reflecting either oil, oil with associated gas, or natural gas well sites, this analysis is based on six model plants: non-low production natural gas well sites, non-low production oil-only well sites, non-low production oil with associated gas well sites, low-production natural gas well sites, low-production oil-only well sites, and low-production oil with associated gas well sites. The facility level cost savings and emission increases from the proposed requirements in this reconsideration were calculated by subtracting the costs and emissions of the model plants under the proposed option (and the alternative options) from the costs and emissions of the model plants under the 2018 baseline. Detailed descriptions of what is included in the cost estimates is also provided in Volume 1 of the TSD.

The cost of certifications being performed by a professional engineer was not included in the analysis of the 2016 NSPS OOOOa rule. This analysis updates baseline cost estimates to include professional engineer certification costs, as well as estimates the savings from allowing

the certifications to be performed by an in-house engineer. The cost of a certification by a professional engineer is estimated to be just under $550 per certification, and the cost of the same certification performed by an in-house engineer is estimated to be about $358 per certification. Therefore, the cost savings per certification is estimated to be about $190 per certification.[21]

2.3.3 Projection of Affected Facilities

The second step in estimating national costs and emissions impacts of the proposed rule is projecting the number of NSPS and reconsideration affected facilities. We first update the number of NSPS affected facilities under the updated 2018 baseline. Then, we estimate the projection of reconsideration affected facilities, which are facilities that would be expected to change their control activities as a result of this reconsideration. Facilities in states with similar state-level requirements and facilities with only recordkeeping requirements are not included within the estimates of affected facilities.

We analyze the effects of this proposal on cost and emissions compared to the 2018 baseline. The 2018 baseline includes the costs and emissions of the projected NSPS affected facilities, after accounting for updated assumptions and data. NSPS affected facilities include facilities that are new or modified since the 2015 NSPS OOOOa proposal, and were/are expected to change control activities as a result of the 2016 NSPS OOOOa, starting from a baseline of a world without the 2016 NSPS OOOOa. Over time, more facilities are newly established or modified in each year, and to the extent the facilities remain in operation in future years, the total number of facilities subject to the 2016 NSPS OOOOa accumulates. As in the final 2016 NSPS RIA, this analysis assumes that all new equipment and facilities established from 2015 through 2024 are still in operation in 2025.

The reconsideration affected facilities are estimated as the subset of the NSPS affected facilities that are expected to change control activities as a result of this reconsideration. These facilities include sources that became affected facilities under the 2016 NSPS OOOOa, prior to the effective date of this action and are assumed to still be in operation, as well as those that are

[21] The costs of certification being performed by a professional engineer and by an in-house engineer are explained fully in the TSD.

projected to become newly affected sources in the future, and are expected to change what their monitoring frequency would have been as a result of this action. For the proposed option, these sources include fugitive emissions sources at well sites and compressor stations on the Alaskan North Slope.[22] Reconsideration affected sources that require a certification are only affected under the projection of newly affected sources. Sources that have already completed professional engineer certifications are not counted as reconsideration affected sources.

The EPA has projected affected facilities using a combination of historical data from the U.S. GHG Inventory (GHGI), DI Desktop, and projected activity levels taken from the Energy Information Administration (EIA) Annual Energy Outlook (AEO). The EPA derived typical counts for new gathering and boosting, and transmission and storage compressor stations by averaging the year-to-year changes over the past ten years in the GHGI. New and modified well sites are based on the count of wells in 2014 from DI Desktop, and projections and growth rates consistent with the drilling activity in the Annual Energy Outlook. For this proposed RIA, the projections have been updated from the 2016 NSPS RIA to reflect the projection estimates in the 2018 AEO.

The 2018 AEO (along with historical year information from previous AEOs) reflects a significant drop in oil and gas drilling between 2014 and 2016, followed by projected increases from 2016 through 2025. While the 2018 AEO projects that oil and gas well drilling will more than double from about 14 thousand wells in 2016 to about 30 thousand wells in 2025, this projection is about 40 percent lower than was projected in the 2015 AEO, which was previously used. In comparison to the 2015 AEO, the 2018 AEO shows about 11 percent lower crude oil production and about 17 percent higher dry natural gas production, indicating an increase in estimated production per well.

This RIA includes an enhanced analysis with respect to previous oil and gas NSPS RIA analyses by including year-by-year results over the 2014 to 2025 analysis period and better disaggregating facilities by vintage and production levels. While it is desirable to analyze impacts beyond 2025 in this RIA, the EPA has chosen not to, largely because of the limited information available to model long-term dynamics in practices and equipment in the oil and gas

[22] We do not quantify any emissions or cost changes associated with new compressor stations on the Alaskan North Slope. See Volume 2 of the TSD for details.

industry. For example, the EPA has limited information on how practices, equipment, and emissions at new facilities evolve as they age or may be shut down. The current analysis assumes that newly established facilities remain in operation for the entire analysis period, which would be less realistic for longer-term analysis. In addition, in a dynamic industry like oil and natural gas, technological progress in control technology is also likely to change significantly over a longer time horizon. For example, the current analysis does not include potential fugitive emissions controls utilizing remote sensing technologies currently under development.

We also reviewed state regulations and permitting requirements which require mitigation measures for many emission sources in the oil and natural gas sector. Detailed information is included in section 3.2.2 of the TSD and in the memorandum *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa* ("State memo"), located at Docket ID No. EPA-HQ-OAR-2017-0483.[23] This analysis was done for the 2016 NSPS RIA, with the states of Colorado, Utah, Ohio and Wyoming expected to result in broadly similar overall emissions reductions. For this RIA, state regulations and permitting requirements were reexamined. While the particular program designs in each of the states examined differs from the 2016 NSPS OOOOa, for the purpose of this RIA analysis, the current requirements in Colorado, Utah, Ohio, Pennsylvania, and California are expected to result in broadly similar overall emissions reductions. California and Pennsylvania have been added as states with similar requirements for this analysis because the requirements in the states have been finalized since the promulgation of the 2016 NSPS OOOOa. The requirements in Wyoming are no longer considered to be equivalent for purposes of the RIA because they are basin specific permit requirements, and are not applicable to the entire state. Requirements in Texas are not included as broadly equivalent requirements in this analysis because they include a permit by rule, which we do consider equivalent in terms of overall emissions reductions. For more information on the states that were examined and why they are or are not considered equivalent, see the TSD and the State memo, both of which are available in the docket.[24]

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[23] For a more detailed explanation of state programs, see section 3.2.2 of the TSD, as well as the memo Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa, located at Docket ID No. EPA-HQ-OAR-2017-0483.

[24] Docket ID No. EPA-HQ-OAR-2017-0483

Applicable facilities in these four states are not included in the estimates of incrementally affected facilities presented in the RIA, as sources in those states would be expected to control emissions at a comparable level regardless of the reconsidered federal standards. This means that any additional costs and benefits incurred by facilities in these states to comply with the federal standards beyond the state requirements (e.g., recordkeeping or verification requirements) are not reflected in this RIA.

[REF _Ref445448353 \h * MERGEFORMAT] presents the number of reconsideration affected sources for each year of analysis after generally accounting for state regulations. In addition to the caveats regarding facilities affected by state regulations described above, facilities with only recordkeeping requirements are also not included within incrementally affected facilities.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Reconsideration Affected Source Counts of the Proposed Option Compared to the 2018 Baseline

Year	Incrementally Affected Sources[1]	Total Affected Sources[2]
2019	21,000	48,000
2020	22,000	56,000
2021	23,000	65,000
2022	23,000	73,000
2023	24,000	82,000
2024	24,000	91,000
2025	24,000	99,000

[1] Incrementally reconsideration affected sources includes sources that are newly affected in each year.
[2] Total reconsideration affected sources includes sources that have to change their control activity as a result of the rule in each year. These include sources that are newly affected in each year plus the sources from previous years that experience a change in their compliance activity as a result of this proposal compared to the 2018 baseline. The table does not include estimated counts of a) affected facilities in states with similar state-level requirements to the proposed option, b) NSPS affected facilities whose controls are unaffected by the reconsideration.

The estimates for affected well sites are based on the count of new and modified wells in 2014 from DI Desktop, and then projected using year by year growth rates from the AEO. The estimates for other affected sources are based upon projections of new sources alone, and do not include replacement or modification of existing sources. While some of these sources are unlikely to be modified, particularly pneumatic pumps and controllers, the impact estimates may be under-estimated due to the focus on new sources. Newly constructed affected facilities are estimated based on averaging the year-to-year changes in the past 10 years of activity data in the Greenhouse Gas Inventory for compressor stations, pneumatic pumps, compressors, and

pneumatic controllers. The approach averages the number of newly constructed units in all years. In years when the total count of equipment decreased, there were assumed to be no newly constructed units.

2.3.4 Emissions Increases

[REF _Ref445289124 \h] summarizes the national increase in emissions associated with the proposed option compared to the updated 2018 baseline as described in Section 2.2. This increase in emissions is estimated by multiplying the unit-level increase in emissions from the updated baseline associated with each applicable control and facility type by the number of incrementally affected sources of that facility type. In this analysis, closed vent system and technical infeasibility certification requirements are not associated with any direct emission reductions; therefore, all emissions increases are attributed to the changes in the fugitive emissions monitoring program. Please note that all results have been rounded.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Increase in Emissions under the Proposed Option Compared to the 2018 Baseline, by year

	Emission Changes			
	Methane (short tons)	**VOC (short tons)**	**HAP (short tons)**	**Methane (metric tons CO_2 Eq.)**
2019	17,000	4,700	180	380,000
2020	21,000	5,700	220	470,000
2021	24,000	6,800	260	550,000
2022	28,000	7,900	300	650,000
2023	33,000	9,100	340	740,000
2024	37,000	10,000	380	830,000
2025	41,000	11,000	430	900,000
Total	**200,000**	**56,000**	**2,100**	**4,500,000**

2.3.5 Forgone Product Recovery

The estimated decrease in costs presented below include the forgone revenue from the reductions in natural gas recovery under the proposed option compared to the 2016 NSPS OOOOa. Fugitive emissions monitoring and repair is assumed to increase the capture of methane and VOC emissions that would otherwise be vented to the atmosphere with no fugitive emissions program, and we assume that a large proportion of the averted methane emissions can be directed into natural gas production streams and sold. In the 2016 NSPS OOOOa, we based the estimated

revenues from those averted natural gas emissions on an estimate of the amount of natural gas that would not be emitted during one year. In this analysis, we estimate the forgone revenue associated with the decrease in natural gas recovery due to this proposed action. Reducing the frequency of the survey and repair program leads to a reduction in the amount of natural gas that is assumed to be captured and sold, leading to forgone revenue in Option 2, the proposed option, and Option 3, the least stringent option, as compared to the 2018 baseline.

[REF _Ref445289011 \h * MERGEFORMAT] summarizes the decrease in natural gas recovery and the associated forgone revenue included in the cost savings calculations. When including the decrease in natural gas recovery in the cost savings analysis, we use the projections of natural gas prices provided in the EIA's 2018 Annual Energy Outlook (AEO) reference case. The AEO projects Henry Hub natural gas prices between $3.40 and $4.07 in $/MMBtu in 2017 dollars.[25] We adjust those prices be between $3.09 and $3.70 in $/Mcf (using the conversion of 1 MMBtu = 1.028 Mcf) in 2016 dollars (using the GDP-Implicit Price Deflator) at the wellhead.[26]

Operators in the gathering and boosting, and transmission and storage parts of the industry do not typically own the natural gas they transport; rather, the operators receive payment for the transportation service they provide. As a result, the unit-level cost and emission reduction analyses supporting best system of emission reduction (BSER) decisions presented in Volume 1 of the TSD do not include estimates of revenue from natural gas recovery as offsets to compliance costs. From a social perspective, however, the increased financial returns from natural gas recovery accrues to entities somewhere along the natural gas supply chain and should be accounted for in the national impacts analysis. An economic argument can be made that, in the long run, no single entity is going to bear the entire burden of the compliance costs or fully receive the financial gain of the additional revenues associated with natural gas recovery. The change in economic surplus resulting from natural gas recovery is going to be spread out amongst different agents via price mechanisms. Therefore, the simplest and most transparent option for allocating these revenues would be to keep the compliance costs and associated revenues together in a given source category and not add assumptions regarding the allocation of

[25] Available at: http://www.eia.gov/forecasts/aeo/tables_ref.cfm.
[26] An EIA study indicated that the Henry Hub price is, on average, about 11 percent higher than the wellhead price. See http://www.eia.gov/oiaf/analysispaper/henryhub/.

these revenues across agents. This is the approach followed in Volume 2 of the TSD, as well as in the 2016 NSPS RIA.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Estimated Decrease in Natural Gas Recovery (Mcf) for the Proposed Option Compared to the 2018 Baseline (millions 2016$)

Year	Decrease in Gas Recovery (Mcf)	Forgone Revenue
2019	0.98	$3.0
2020	1.2	$4.0
2021	1.4	$4.7
2022	1.6	$5.5
2023	1.9	$6.6
2024	2.1	$7.6
2025	2.4	$8.8

2.3.6 Compliance Cost Savings

[REF _Ref445289220 \h] summarizes the cost savings and foregone revenue from product recovery for the evaluated emissions sources and points. What we call planning costs in this analysis were a part of the capital cost estimates in the 2016 NSPS RIA, however, in this RIA we assume there are no capital equipment purchases. Instead, the analogous costs in this RIA include the cost of creating the survey monitoring plan for the fugitives monitoring requirement and completing the required certifications. The annual operating and maintenance cost savings are all attributed to the fugitives monitoring requirement, and include the cost of performing the surveys, as well as the costs of performing repairs. The planning cost savings in the table represents savings in the total planning cost expenditures associated with affected units, including the change in planning cost expenditures made by sources affected prior to the analysis year. The cost savings are estimated by multiplying the unit level cost savings from the updated baseline associated with applicable control and facility type, as explained in section 2.3.2, by the number of incrementally affected sources of that facility type. In addition, the cost savings from the streamlining of recordkeeping and reporting are included in the annualized cost savings totals.[27] These cost savings are described more below.

[27] See preamble section 60.5420a for details on the proposed amendments to the recordkeeping and reporting requirements.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Compliance Cost Savings Estimates for Proposed Option Compared to the 2018 Baseline (millions 2016$)

	Compliance Cost Savings				
Year	**Planning Cost Savings[1]**	**Operating and Maintenance Cost Savings**	**Annualized Cost Savings (w/o Forgone Product Revenue)[2]**	**Forgone Revenue from Product Recovery**	**Nationwide Annualized Cost Savings with Forgone. Revenue**
2019	$2.8	$28	$32	$3.0	$29
2020	$3.0	$34	$38	$4.0	$34
2021	$3.0	$41	$45	$4.7	$40
2022	$3.1	$47	$51	$5.5	$46
2023	$3.5	$54	$58	$6.6	$52
2024	$3.4	$61	$65	$7.6	$58
2025	$3.5	$68	$72	$8.8	$64

[1] The planning cost savings include the cost savings incurred by the newly affected sources for both fugitive emissions monitoring and certifications in each year, as well as the cost savings of fugitive emissions sources that renew survey monitoring plans after 8 years.
[2] These cost savings include the planning cost savings for all fugitive emissions requirements annualized over 8 years at an interest rate of 7 percent, plus the annual operating and maintenance cost savings for the fugitive emissions requirements every year, plus the cost savings of certifications in each year, plus the cost savings from streamlined recordkeeping and reporting.
Sums may not total due to independent rounding.

The cost of designing, or redesigning, the fugitive emissions monitoring program occurs every 8 years to comply with the 2016 NSPS OOOOa requirements. The lifetime of the monitoring program does not change in this reconsideration. The reduction in planning costs in each year outlined in [REF _Ref445289220 \h] includes the estimated reduction in the costs of designing a fugitive emissions monitoring program for the new reconsideration affected sources in that year, plus the reduction in the cost of redesigning an existing program for sources that became affected previously. The first year a redesign cost is included in the planning cost calculation is 2023, as we assume the first NSPS affected sources completed monitoring plans in 2016, the first year the 2016 NSPS OOOOa affected sources completed compliance activities. The decrease in these program design costs were added to the cost savings of closed vent system and technical infeasibility certifications in each year to get the total planning cost savings for each year.

The fugitive emissions monitoring program design cost savings annualized over the expected lifetime of 8 years at an interest rate of 7 percent, is added to the annual cost savings of implementing the fugitive emissions monitoring program, the cost savings of in house certifications in each year, and the cost savings from streamlined recordkeeping and reporting to

get the annualized cost savings in each year compared to the 2018 baseline. The forgone value of product recovery is then added to estimate the total annualized cost savings in each year.

[REF _Ref510773373 \h] illustrates the sensitivity of compliance cost and emissions analysis results of the proposed option to choice of discount rate. We present costs using a discount rate of 7 percent and 3 percent based on the Office of Management and Budget (OMB) Circular A-4.[28] The table shows that the choice of discount rate has minor effects on the nationwide annualized cost savings of the proposed rule.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Estimated Cost Savings of the Proposed Option, 2019-2025, using 3 and 7 Percent Discount Rates (millions 2016$)

	7 Percent			3 Percent		
Year	**Annualized Cost Savings (without Product Recovery)**	**Forgone Revenue from Product Recovery**	**Nationwide Annualized Cost Savings with Product Recovery**	**Annualized Cost Savings (without Product Recovery)**	**Forgone Revenue from Product Recovery**	**Nationwide Annualized Cost Savings with Product Recovery**
2019	$32	$3.0	$29	$32	$3.0	$28
2020	$38	$4.0	$34	$38	$4.0	$34
2021	$45	$4.7	$40	$44	$4.7	$40
2022	$51	$5.5	$46	$51	$5.5	$46
2023	$58	$6.6	$52	$58	$6.6	$52
2024	$65	$7.6	$58	$65	$7.6	$58
2025	$72	$8.8	$64	$72	$8.8	$63

The choice of discount rate has a very small effect on nationwide annualized cost savings. Discount rate generally affects estimates of annualized costs for controls with high planning or capital costs relative to annual costs. In this analysis, the planning cost savings related to fugitive emissions surveys, plus the cost savings of closed vent system design and technical infeasibility certifications, are small relative to the annual cost savings related to fugitive emissions surveys, so the interest rate has little impact on annualized cost savings for these sources.

Reporting and recordkeeping costs were drawn from the information collection requirements (ICR) in this final rule that have been submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act (see Preamble for more

[28] Found at: https://obamawhitehouse.archives.gov/omb/circulars_a004_a-4/#e

detail). The reporting and recordkeeping cost savings in this RIA are estimated to be constant at about $810,000 every year. These recordkeeping and recordkeeping cost savings are estimated for the selected Option 2 for all new and modified affected facilities regardless of whether they are in states with regulatory requirements similar to the final 2016 NSPS OOOOa. While these cost savings may differ across regulatory options as a result of the varying frequency of the fugitive emissions program across the options, we do not have the information to estimate the ICR burden for the unselected Option 1 and 3. As a result, we assume all options have the same recordkeeping and reporting cost burden. Note also that the total reporting and recordkeeping cost savings from streamlining the requirements is mitigated by the estimated cost of reading the proposed rule.

2.3.7 Comparison of Regulatory Alternatives

[REF _Ref506472384 \h] presents a comparison of the regulatory alternatives through each step of the emissions analysis in 2020 and 2025. The options vary with respect to the fugitive emissions requirements at well sites. The less stringent option, Option 3, reduces monitoring at low production wells to biennial (every other year), exempts well sites on the Alaskan North Slope from fugitive emissions monitoring requirements, and requires annual monitoring for all other affected, non-low production wells sites. Compressor stations on the Alaskan North Slope are exempt from fugitive emissions monitoring, while compressor stations located elsewhere require quarterly fugitive emissions monitoring.[29] Option 3 results in greater increases in emissions and smaller cost savings compared to the proposed Option 2. The more stringent option, Option 1, would finalize no changes in the fugitive emissions requirements from the 2016 NSPS OOOOa requirements, but amends the requirement for closed vent systems and pneumatic pump technical infeasibility to allow the use of an in-house engineer. There are no changes in emissions compared to the 2018 baseline, and the cost savings are smaller than under the proposed Option 2. We assume biennial, annual, stepped, semiannual, and quarterly fugitive emissions surveys result in reductions in emissions of 30 percent, 40 percent, 45 percent,

[29] See section V.B.1 of the preamble, section 2 of the TSD and section 2.5.2 below for further discussion on choice of fugitive emissions monitoring frequency.

60 percent and 80 percent, respectively.[30] Natural gas recovery also varies as a result of survey frequency. The different survey frequencies, as shown in [REF _Ref445289042 \h], also affect the count of reconsideration affected sources, which leads to variations in the natural gas recovery, and therefore the value of natural gas recovery, as well as planning and annualized costs.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Comparison of Regulatory Alternatives to 2018 Baseline, 2020 and 2025

	Regulatory Alternative		
	Option 1*	**Option 2 (Proposed)**	**Option 3**
Total Impacts, 2020			
Increase in Emissions			
Methane Emissions (short tons/year)	0	21,000	28,000
VOC Emissions (short tons/year)	0	5,700	8,000
Decrease in Natural Gas Recovery (Mcf) (millions)	0	1.2	1.6
Cost Savings			
Planning Cost Savings	$2.7	$3.0	$3.1
Annualized Cost Savings w/o Forgone Revenue	$3.5	$38	$51
Annualized Cost Savings with Forgone Revenue	$3.5	$34	$46
Total Impacts, 2025			
Increase in Emissions			
Methane Emissions (short tons/year)	0	41,000	56,000
VOC Emissions (short tons/year)	0	11,000	16,000
Decrease in Natural Gas Recovery (Mcf) (millions)	0	2.4	3.3
Cost Saving			
Planning Cost Savings	$2.9	$3.5	$3.7
Annualized Cost Savings w/o Forgone Revenue	$3.7	$72	$98
Annualized Cost Savings with Forgone Revenue	$3.7	$64	$86

* The small difference between the planning cost savings and the annualized cost savings values for option 1 are due to the cost savings from proposed amendments to the recordkeeping and reporting requirements.

As can be seen in [REF _Ref510773419 \h], the most stringent Option 1 results in the smallest decrease in annualized costs ($3.5 million in 2020 and $3.7 million in 2025), as well as the smallest increase in emissions (at 0 tons). The proposed Option 2 results in a decrease of

[30] For the proposed option, the fugitives monitoring survey frequency is stepped from semiannual for two years down to annual thereafter. The emission reductions for the stepped option averages out to 45 percent per year over the eight-year lifetime of the fugitive emissions monitoring plan. See the TSD for more details on this and the estimate for emission reductions under a biennial fugitive monitoring survey frequency.

about $34 million in annualized costs in 2020 and $64 million in 2025, after accounting for the value of the decrease in product recovery. Option 2 also results in an estimated increase of about 21,000 short tons per year of methane emissions and 5,700 tons per year in VOC emissions in 2020, and 41,000 short tons per year methane emissions and 11,000 tons per year in VOC emissions in 2025. The least stringent Option 3 results in the largest decrease in costs, as well as the largest increase in emissions. Option 3 is associated with an estimated decrease of about $46 million in annualized costs in 2020 and $86 million in 2025, after accounting for the value of the decrease in product recovery. Option 3 also results in an estimated increase of about 28,000 short tons per year methane emissions and 8,000 tons per year in VOC emissions in 2020, and 56,000 short tons per year methane emissions and 16,000 tons per year in VOC emissions in 2025.

2.4 Detailed Impacts Tables

The following tables show the full details of the cost savings and increase in emissions by emissions sources for each regulatory option in 2020 and 2025.

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Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Incrementally Affected Units, Emissions Increases and Cost Savings, Option 1, 2020

		Total Increase in Emissions				National Cost Savings			
Source/Emissions Point	**Projected No. of Reconsideration Affected Sources**	**Methane (short tons)**	**VOC (short tons)**	**HAP (short tons)**	**Methane (metric tons CO2e)**	**Planning Cost Savings**	**Operating and Maintenance**	**Forgone Product Recovery**	**Total Annualized Cost Savings with Forgone Revenues**
Fugitive Emissions									
Well sites	0	0	0	0	0	$0	$0	$0	$0
Gathering and Boosting Stations	0	0	0	0	0	$0	$0	$0	$0
Transmission Compressor Stations	0	0	0	0	0	$0	$0	$0	$0
Certifications									
CVS and Technical Infeasibility	14,000	0	0	0	0	$2.7	$0	$0	$2.7
Reporting and Recordkeeping	All	0	0	0	0	$0	$0	$0	$0.81
TOTAL	**14,000**	**0**	**0**	**0**	**0**	**$2.7**	**$0**	**$0**	**$3.5**

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Incrementally Affected Units, Emissions Increases and Cost Savings, Option 1, 2025

		Total Increase in Emissions				National Cost Savings			
Source/Emissions Point	**Projected No. of Reconsideration Affected Sources**	**Methane (short tons)**	**VOC (short tons)**	**HAP (short tons)**	**Methane (metric tons CO2e)**	**Planning Cost Savings**	**Operating and Maintenance**	**Forgone Product Recovery**	**Total Annualized Cost Savings with Forgone Revenues**
Fugitive Emissions									
Well sites	0	0	0	0	0	$0	$0	$0	$0
Gathering and Boosting Stations	0	0	0	0	0	$0	$0	$0	$0
Transmission Compressor Stations	0	0	0	0	0	$0	$0	$0	$0
Certifications									
CVS and Technical Infeasibility	15,000	0	0	0	0	$2.9	$0	$0	$2.9
Reporting and Recordkeeping	All	0	0	0	0	$0	$0	$0	$0.81
TOTAL	**15,000**	**0**	**0**	**0**	**0**	**$2.9**	**$0**	**$0**	**$3.7**

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Incrementally Affected Units, Emissions Increases and Cost Savings, Proposed Option 2, 2020

		Total Increase in Emissions				National Cost Savings			
Source/Emissions Point	**Projected No. of Reconsideration Affected Sources**	**Methane (short tons)**	**VOC (short tons)**	**HAP (short tons)**	**Methane (metric tons CO2e)**	**Planning Cost Savings**	**Operating and Maintenance**	**Forgone Product Recovery**	**Total Annualized Cost Savings with Forgone Revenues**
Fugitive Emissions									
Well sites	42,000	21,000	5,700	220	470,000	$0.27	$34	$4.0	$30
Gathering and Boosting Stations	0	0	0	0	0	$0	$0	$0	$0
Transmission Compressor Stations	0	0	0	0	0	$0	$0	$0	$0.0
Certifications									
CVS and Technical Infeasibility	14,000	0	0	0	0	$2.7	$0	$0	$2.7
Reporting and Recordkeeping	All	0	0	0	0	$0	$0	$0	$0.81
TOTAL	**56,000**	**21,000**	**5,700**	**220**	**470,000**	**$3.0**	**$34**	**$4.0**	**$34**

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Incrementally Affected Units, Emissions Increases and Cost Savings, Proposed Option 2, 2025

Source/Emissions Point	Projected No. of Reconsideration Affected Sources	Total Increase in Emissions				National Cost Savings			
		Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO2e)	Planning Cost Savings	Operating and Maintenance	Forgone Product Recovery	Total Annualized Cost Savings with Forgone Revenues
Fugitive Emissions									
Well sites	84,000	41,000	11,000	430	930,000	$0.57	$68	$8.8	$63
Gathering and Boosting Stations	0	0	0	0	0	$0	$0	$0	$0
Transmission Compressor Stations	0	0	0	0	0	$0	$0	$0	$0
Certifications									
CVS and Technical Infeasibility	15,000	0	0	0	0	$2.9	$0	$0	$2.9
Reporting and Recordkeeping	All	0	0	0	0	$0	$0	$0	$0.81
TOTAL	**99,000**	**41,000**	**11,000**	**430**	**930,000**	**$3.5**	**$68**	**$8.8**	**$64**

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Incrementally Affected Units, Emissions Increases and Cost Savings, Option 3, 2020

Source/Emissions Point	Projected No. of Reconsideration Affected Sources	Total Increase in Emissions				National Cost Savings			
		Methane (short tons)	VOC (short tons)	HAP (short tons)	Methane (metric tons CO2e)	Planning Cost Savings	Operating and Maintenance	Forgone Product Recovery	Total Annualized Cost Savings with Forgone Revenues
Fugitive Emissions									
Well sites	42,000	28,000	7,800	300	640,000	$0.38	$47	$5.5	$42
Gathering and Boosting Stations	0	0	0	0	0	$0	$0	$0	$0
Transmission Compressor Stations	0	0	0	0	0	$0	$0	$0	$0
Certifications									
CVS and Technical Infeasibility	14,000	0	0	0	0	$2.7	$0	$0	$2.7
Reporting and Recordkeeping	All	0	0	0	0	$0	$0	$0	$0.81
TOTAL	**56,000**	**28,000**	**7,800**	**300**	**640,000**	**$3.1**	**$47**	**$5.5**	**$46**

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Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Incrementally Affected Units, Emissions Increases and Cost Savings, Option 3, 2025

		Total Increase in Emissions				National Cost Savings			
Source/Emissions Point	**Projected No. of Reconsideration Affected Sources**	**Methane (short tons)**	**VOC (short tons)**	**HAP (short tons)**	**Methane (metric tons CO2e)**	**Planning Cost Savings**	**Operating and Maintenance**	**Forgone Product Recovery**	**Total Annualized Cost Savings with Forgone Revenues**
Fugitive Emissions									
Well sites	84,000	56,000	16,000	590	1,300,000	$0.79	$94	$12	$83
Gathering and Boosting Stations	0	0	0	0	0	$0	$0	$0	$0
Transmission Compressor Stations	0	0	0	0	0	$0	$0	$0	$0
Certifications									
CVS and Technical Infeasibility	15,000	0	0	0	0	$2.9	$0	$0	$2.9
Reporting and Recordkeeping	All	0	0	0	0	$0	$0	$0	$0.81
TOTAL	**99,000**	**56,000**	**16,000**	**590**	**1,300,000**	**$3.7**	**$94**	**$12**	**$86**

2.5 Analysis of the Present Value of Cost Savings

This section presents the economic cost impacts of the proposed action in a present value (PV) framework in compliance with E.O. 13771, Reducing Regulation and Controlling Regulatory Costs. The proposed action, if finalized, would be considered a deregulatory action as it has total costs that are less than zero. The stream of the estimated cost savings for each year from 2019 through 2025 is discounted back to 2016 using both a 7 and 3 percent discount rate, and summed to estimate the PV of the cost savings. This PV represents the sum of the total annual cost savings over the 2019 to 2025-time horizon as a result of this proposed action. The PV is then used to estimate the equivalent annualized value (EAV) of the cost savings. The EAV is the annualized PV of the cost savings. In other words, the EAV takes the "lumpy" stream of cost savings and converts them into a single value that, when added together, equals the original stream of values in PV terms.

As above, all costs are cost savings, and are presented as the change in costs of the proposed option compared to the 2018 baseline, and are in 2016 dollars. Section 2.4 above presents the annualized cost savings of the proposed option, however the cost savings used to estimate the PV are the un-annualized cost savings in each year. In the case of this analysis, using the annualized values would return results very similar to using the unannualized values because the portion of the total cost savings that is annualized is very small.

2.5.1 Present Value and Equivalent Annualized Value of the Cost Savings

For this RIA, the EPA evaluates the change in costs for each year where reconsideration affected sources are expected to change their compliance activities from the 2016 NSPS OOOOa requirements as a result of this reconsideration, through 2025. In the case of this proposed action, the change in compliance activates leads to cost savings. The EPA has chosen not to evaluate impacts beyond 2025 in part due to the limited information available to model long-term dynamics in practices and equipment in the oil and gas industry. In addition, the oil and natural gas industry is dynamic, and technological progress in control technology is likely to change significantly over a longer time horizon.

[REF _Ref507149124 \h] shows the stream of cost savings for each year from 2019 through 2025. Planning cost savings are estimated as the sum of the difference in costs of the

design of fugitive emissions monitoring plans for new reconsideration affected facilities, the difference in costs of the redesign of fugitive emissions monitoring plans for reconsideration affected facilities that were affected by the 2016 NSPS OOOOa at least 8 years prior, and the difference in costs of certification for closed vent system design and pneumatic pump technical infeasibility for new reconsideration affected sources compared to the updated baseline. Total cost savings are the sum of the planning cost savings and annual operating cost savings. The forgone revenue from the decrease in product recovery is estimated using the AEO 2018 projected natural gas price, as described in section 2.4.4. Total cost savings with forgone revenue is the total cost savings minus the forgone revenue. Over time, with the addition of new reconsideration affects sources, the planning cost savings, annual operating cost savings and forgone revenue increase.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Estimated Cost Savings for the Proposed Option, 2019-2025 (millions 2016$)

Year	Planning Cost Savings[1]	Operating and Maintenance Cost Savings	Total Cost Savings Without Forgone Revenue	Forgone Revenue from Product Recovery	Total Cost Savings with Forgone Revenue[2]
2019	$2.8	$28	$32	$3.0	$29
2020	$3.0	$34	$38	$4.0	$34
2021	$3.0	$41	$45	$4.7	$40
2022	$3.1	$47	$51	$5.5	$46
2023	$3.5	$54	$59	$6.6	$52
2024	$3.4	$61	$65	$7.6	$58
2025	$3.5	$68	$72	$8.8	$64

[1] The planning cost savings include the cost savings incurred by the newly affected sources for both fugitive emissions monitoring and certifications in each year, as well as the cost savings of fugitive emissions sources that renew survey monitoring plans after 8 years.
[2] Total cost savings include the planning cost savings for all fugitive emissions, plus the annual operating and maintenance cost savings for the fugitive emissions requirements every year, plus the cost savings of certifications in each year, plus the cost savings from streamlined recordkeeping and reporting.
Sums may not total due to independent rounding.

[REF _Ref506472401 \h] shows the stream of cost savings discounted to 2016 using a 7 percent discount rate. The table also shows the PV and the EAV of planning cost savings, annual operating cost savings, forgone revenue from decreased product recovery and the total cost savings (after accounting for the forgone product recovery). The PV of total cost savings is $209 million, and the EAV of total cost savings is about $36 million per year.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Discounted Cost Savings Estimates for Proposed Option Compared to the 2018 Baseline Using a 7 Percent Discount Rate (millions 2016$)*

	Discounted Compliance Cost Savings			
Year	**Planning Cost Savings[1]**	**Operating and Maintenance Cost Savings**	**Forgone Revenue from Product Recovery**	**Total Cost Savings with Forgone Revenue[2]**
2019	$2.3	$23	$2.5	$23
2020	$2.3	$26	$3.1	$26
2021	$2.2	$29	$3.4	$28
2022	$2.1	$32	$3.7	$30
2023	$2.2	$34	$4.1	$32
2024	$2.0	$36	$4.4	$34
2025	$1.9	$37	$4.8	$35
PV	**$15**	**$216**	**$26**	**$209**
EAV	**$2.6**	**$37**	**$4.5**	**$36**

* The cost savings in each year are discounted to 2016.
[1] The planning cost savings include the cost savings incurred by the newly affected sources for both fugitive emissions monitoring and certifications in each year, as well as the cost savings of fugitive emissions sources that renew survey monitoring plans after 8 years discounted to 2016.
[2] Total cost savings include the planning cost savings for all fugitive emissions, plus the annual operating and maintenance cost savings for the fugitive emissions requirements every year, plus the cost savings of certifications in each year, plus the cost savings from streamlined recordkeeping and reporting discounted to 2016.
Sums may not total due to independent rounding.

[REF _Ref507159345 \h] shows the discounted cost savings of the proposed option, as well as the two alternative options, over 2019 through 2025 compared to the 2018 baseline, along with the PV and EAV of those cost savings, estimated using a 7 percent discount rate. Option 1 does not affect the fugitive emissions monitoring requirements, and therefore product recovery is not affected. Option 1 results in a savings of about $17 million in the PV, or $2.9 million per year in the EAV. Option 2, the proposed option, results in a larger decrease: about $209 million in the PV of total cost savings, after accounting for the forgone value of the decrease in product recovery, or about $36 million per year in the EAV. Option 3 leads to a PV of about $282 million in savings than the 2018 baseline, after accounting for the forgone value of the decrease in product recovery, or about $49 million per year in the EAV.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Comparison of Regulatory Alternatives to 2018 Baseline Using a 7 Percent Discount Rate

	Regulatory Alternatives		
	Option 1	**Option 2 (Proposed)**	**Option 3**
PV of Cost Savings			
Compliance Cost Savings (millions 2016$)			
Planning Cost Savings	$13	$15	$15
Total Cost Savings w/o Forgone Revenue	$17	$234	$317
Total Cost Savings with Forgone Revenue	$17	$209	$282
EAV of Cost Savings			
Compliance Cost Savings (millions 2016$)			
Planning Cost Savings	$2.3	$2.6	$2.7
Total Cost Savings w/o Forgone Revenue	$2.9	$41	$55
Total Cost Savings with Forgone Revenue	$2.9	$36	$49

[REF _Ref507159956 \h] shows how the choice of discount rate affects the PV and EAV estimates. A lower discount rate results in the higher cost savings in later years having a greater impact on the PV and EAV than would results under a higher discount rate. The PV and EAV for the cost savings are higher when using a 3 percent discount rate than when using a 7 percent discount rate. Using a 3 percent discount rate increases the PV of the cost savings by between 27 and 28 percent from the estimates using a 7 percent discount rate. For the EAV, using a 3 percent discount rate increases the cost savings by between 14 and 15 percent from the estimates using a 7 percent discount rate.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Discounted Cost Savings for the Proposed Option using 7 and 3 Percent Discount Rates Compared to the 2018 Baseline (millions 2016$)*

	7 Percent			3 Percent		
Year	**Total Annual Cost Savings (without forgone revenue)**	**Forgone Revenue from Product Recovery**	**Total Cost Savings (with forgone revenue)[1]**	**Total Annual Cost Savings (without forgone revenue)**	**Forgone Revenue from Product Recovery**	**Total Cost Savings (with forgone revenue)[1]**
2019	$26	$2.5	$23	$29	$2.8	$26
2020	$29	$3.1	$26	$34	$3.6	$30
2021	$32	$3.4	$28	$38	$4.1	$34
2022	$34	$3.7	$30	$43	$4.6	$38
2023	$36	$4.1	$32	$48	$5.3	$42
2024	$38	$4.4	$34	$52	$6.0	$46
2025	$39	$4.8	$35	$55	$6.7	$49
PV	**$234**	**$26**	**$209**	**$299**	**$33**	**$265**
EAV	**$41**	**$4.5**	**$36**	**$47**	**$5.2**	**$41**

*The cost savings in each year are discounted to 2016.
[1] Total cost savings include the planning cost savings for all fugitive emissions, plus the annual operating and maintenance cost savings for the fugitive emissions requirements every year, plus the cost savings of certifications in each year, plus the cost savings from streamlined recordkeeping and reporting discounted to 2016.
Sums may not total due to independent rounding.

2.5.2 Sensitivity of Cost Savings to Fugitive Emissions Monitoring Frequency at Compressor Stations

The requirements under the proposed option are chosen individually and represent the best system of emission reduction (BSER) for each source based on the information we have available. This analysis was performed for the 2016 OOOOa NSPS, and revisited for this action. Under the data we currently have available, combined with the unique operating characteristics of compressor stations, we cannot support changing the monitoring frequency at compressor stations from quarterly. Section V.B.1 of the preamble and section 2 of the TSD contain discussions of the different fugitive emissions monitoring frequencies, as well as a discussion of why we cannot support changing the monitoring frequency at compressor stations. Section V.B.1 of the preamble also contains solicitations for specific information we need in order to reevaluate monitoring frequencies.

We recognize that there are possible alternative frequencies. In this section, we provide an analysis of the total cost savings of the action under these alternative monitoring frequencies

for compressor stations. [REF _Ref516660271 \h] contains the PV and EAV of the total cost savings and the total increase in emissions under each alternative frequency. All other aspects of the requirements remain as outlined under the proposed option. The cost savings and increase in emissions are measured as changes from the 2018 baseline, and cost savings are discounted to 2016 using a 7 percent discount rate, and are in millions of 2016$. The total emissions are the sum of the increase in emissions from 2019 through 2025.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Total Cost Savings and Increase in Emissions of the Proposed Option Under Alternative Monitoring Frequencies at Compressor Stations

	Proposed Option (Quarterly)	Semiannual	Annual
Present Value			
Total Cost Savings	$209	$304	$352
Cost Savings	*$234*	*$343*	*$403*
Forgone Value of Product Recovery	*$26*	*$39*	*$52*
Equivalent Annualized Cost			
Total Cost Savings	$36	$53	$61
Cost Savings	*$41*	*$60*	*$70*
Forgone Value of Product Recovery	*$4.5*	*$6.7*	*$9.0*
Total Emissions Increase (2019 through 2025)			
Methane (short tons)	200,000	300,000	410,000
VOC (short tons)	56,000	79,000	100,000
HAP (short tons)	2,100	3,000	3,900
Methane (million metric tons CO_2 Eq.)	4.5	6.9	9.2

[1] Total cost savings include the planning cost savings for all fugitive emissions, the annual operating and maintenance cost savings for the fugitive emissions requirements every year, the cost savings of certifications in each year, the cost savings from streamlined recordkeeping and reporting, and the forgone revenue from the decrease in product recovery, discounted to 2016.
Totals may not sum due to independent rounding.

Table 2-18 presents a comparison of the proposed option, which requires quarterly monitoring at compressor stations, with two alternative alternatives that vary only with respect to the frequency of the fugitive emissions monitoring requirements for compression stations. All other requirements are those of the proposed option, as shown in [REF _Ref445289042 \h * MERGEFORMAT]. The cost savings, forgone value of product recovery, and total emissions increase under both semiannual and annual monitoring. When reducing monitoring frequency from quarterly to semiannual, total cost savings increase by about 46 percent, methane emissions increase by about 50 percent, VOC emissions increase by about 41 percent, and HAP emissions increase by about 43 percent. When reducing monitoring frequency from quarterly to annual,

total cost savings increase by about 69%, methane emissions increase by 105 percent, VOC emissions increase by 79 percent, and HAP emissions increase by about 86 percent.

3 ESTIMATED FORGONE BENEFITS

3.1 Introduction

The 2016 NSPS OOOOa regulated methane and VOC emissions in the oil and natural gas sector. For the 2016 NSPS OOOOa, the EPA predicted climate and ozone benefits from methane reductions, ozone and fine particulate matter ($PM_{2.5}$) health benefits from VOC reductions, and health benefits from ancillary HAP emission reduction. These benefits were expected to occur because the control techniques to meet the standards simultaneously reduce methane, VOC, and HAP emissions.[31] Under the updated assumptions and data as described above, the sources that are affected by this reconsideration would have prevented an estimated 120,000 tons of methane, and 32,000 tons of VOC from new sources in 2020 assuming no changes to the regulation. In 2025, the affected sources would have prevented an estimated 240,000 tons of methane and 62,000 tons of VOC. The estimated CO_2-equivalent (CO_2 Eq.) methane emission reductions would have been about 2.8 million metric tons in 2020 and 5.4 million metric tons in 2025. As described in the subsequent sections of this chapter, these pollutants are associated with substantial climate, health, and welfare effects.

As in the 2016 NSPS RIA, the only estimated forgone benefits monetized in this RIA are methane-related climate impacts. The proposed option is estimated to increase emissions compared to the 2018 baseline. The total increase in emissions over 2019 through 2025 is estimated to be about 200,000 short tons of methane, 56,000 tons of VOC and 2,100 tons of HAP. The associated increase in CO_2 Eq. methane emissions is estimated to be 4.5 million metric tons. The PV of the forgone methane-related climate benefits are estimated to be $7.2 million from 2019 through 2025 using an interim estimate of the domestic social cost of methane (SC-CH_4) discounting at a 7 percent rate. The associated EAV is estimated to be $1.2 million per year. Using the interim SC-CH_4 estimate based on the 3 percent rate, the PV of the forgone domestic climate benefits is estimated to be $28 million; the EAV is estimated to be $4.4 million per year.

[31] The specific control techniques for the 2016 NSPS OOOOa were also anticipated to have minor disbenefits resulting from secondary emissions of carbon dioxide (CO_2), nitrogen oxides (NO_X), PM, carbon monoxide (CO), and total hydrocarbons (THC)), and emission changes associated with the energy markets impacts. The proposed action is anticipated to reduce these minor secondary emissions.

While we expect that the forgone VOC emission reductions may also degrade air quality and adversely affect health and welfare effects associated with exposure to ozone, $PM_{2.5}$, and HAP, data limitations prevent us from quantifying forgone VOC-related health benefits. This omission should not imply that these forgone benefits may not exist; rather, it reflects the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available. With these data currently unavailable, we are unable to estimate forgone health benefits estimates for this rule due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with HAP and VOC reductions.[32] In this chapter, we qualitatively assess the forgone health benefits associated with reducing exposure to these pollutants, as well as visibility impairment and forgone ecosystem benefits. [REF _Ref445289936 \h] summarizes the quantified and unquantified forgone benefits in this analysis.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Climate and Human Health Effects of Forgone Emission Reductions from this Proposed Rule

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
Improved Environment				
Reduced climate effects	Climate impacts from methane (CH_4) and carbon dioxide (CO_2)	—[1]	✓	Section 3.3
	Other climate impacts (e.g., ozone, black carbon, aerosols, other impacts)	—	—	IPCC, Ozone ISA, PM ISA[2]
Improved Human Health				
Reduced incidence of premature mortality from exposure to $PM_{2.5}$	Adult premature mortality based on cohort study estimates and expert elicitation estimates (age >25 or age >30)	—	—	PM ISA[3]
	Infant mortality (age <1)	—	—	PM ISA[3]
Reduced incidence of morbidity from exposure to $PM_{2.5}$	Non-fatal heart attacks (age > 18)	—	—	PM ISA[3]
	Hospital admissions—respiratory (all ages)	—	—	PM ISA[3]
	Hospital admissions—cardiovascular (age >20)	—	—	PM ISA[3]
	Emergency room visits for asthma (all ages)	—	—	PM ISA[3]

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

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
	Acute bronchitis (age 8-12)	—	—	PM ISA[3]
	Lower respiratory symptoms (age 7-14)	—	—	PM ISA[3]
	Upper respiratory symptoms (asthmatics age 9-11)	—	—	PM ISA[3]
	Asthma exacerbation (asthmatics age 6-18)	—	—	PM ISA[3]
	Lost work days (age 18-65)	—	—	PM ISA[3]
	Minor restricted-activity days (age 18-65)	—	—	PM ISA[3]
	Chronic Bronchitis (age >26)	—	—	PM ISA[3]
	Emergency room visits for cardiovascular effects (all ages)	—	—	PM ISA[3]
	Strokes and cerebrovascular disease (age 50-79)	—	—	PM ISA[3]
	Other cardiovascular effects (e.g., other ages)	—	—	PM ISA[2]
	Other respiratory effects (e.g., pulmonary function, non-asthma ER visits, non-bronchitis chronic diseases, other ages and populations)	—	—	PM ISA[2]
	Reproductive and developmental effects (e.g., low birth weight, pre-term births, etc.)	—	—	PM ISA[2,4]
	Cancer, mutagenicity, and genotoxicity effects	—	—	PM ISA[2,4]
Reduced incidence of mortality from exposure to ozone	Premature mortality based on short-term study estimates (all ages)	—	—	Ozone ISA[3]
	Premature mortality based on long-term study estimates (age 30–99)	—	—	Ozone ISA[3]
Reduced incidence of morbidity from exposure to ozone	Hospital admissions—respiratory causes (age > 65)	—	—	Ozone ISA[3]
	Hospital admissions—respiratory causes (age <2)	—	—	Ozone ISA[3]
	Emergency department visits for asthma (all ages)	—	—	Ozone ISA[3]
	Minor restricted-activity days (age 18–65)	—	—	Ozone ISA[3]
	School absence days (age 5–17)	—	—	Ozone ISA[3]
	Decreased outdoor worker productivity (age 18–65)	—	—	Ozone ISA[3]
	Other respiratory effects (e.g., premature aging of lungs)	—	—	Ozone ISA[2]
	Cardiovascular and nervous system effects	—	—	Ozone ISA[2]
	Reproductive and developmental effects	—	—	Ozone ISA[2,4]
Reduced incidence of morbidity from exposure to HAP	Effects associated with exposure to hazardous air pollutants such as benzene	—	—	ATSDR, IRIS[2,3]
Improved Environment				
Reduced visibility impairment	Visibility in Class 1 areas	—	—	PM ISA[3]
	Visibility in residential areas	—	—	PM ISA[3]
Reduced effects from PM deposition (organics)	Effects on Individual organisms and ecosystems	—	—	PM ISA[2]
Reduced vegetation and ecosystem effects from exposure to ozone	Visible foliar injury on vegetation	—	—	Ozone ISA[3]
	Reduced vegetation growth and reproduction	—	—	Ozone ISA[3]
	Yield and quality of commercial forest products and crops	—	—	Ozone ISA[3]
	Damage to urban ornamental plants	—	—	Ozone ISA[2]

Category	Specific Effect	Effect Has Been Quantified	Effect Has Been Monetized	More Information
	Carbon sequestration in terrestrial ecosystems	—	—	Ozone ISA[3]
	Recreational demand associated with forest aesthetics	—	—	Ozone ISA[2]
	Other non-use effects			Ozone ISA[2]
	Ecosystem functions (e.g., water cycling, biogeochemical cycles, net primary productivity, leaf-gas exchange, community composition)	—	—	Ozone ISA[2]

[1] The climate and related impacts of CO_2 and CH_4 emissions changes, such as sea level rise, are estimated within each integrated assessment model as part of the calculation of the domestic SC-CO_2 and SC-CH_4. The resulting monetized damages, which are relevant for conducting the benefit-cost analysis, are used in this RIA to estimate the domestic welfare effects of quantified changes in CH_4 emissions.
[2] We assess these benefits qualitatively because we do not have sufficient confidence in available data or methods.
[3] We assess these benefits qualitatively due to data limitations for this analysis, but we have quantified them in other analyses.
[4] We assess these benefits qualitatively because current evidence is only suggestive of causality or there are other significant concerns over the strength of the association.

3.2 Forgone Emissions Reductions

Oil and natural gas operations in the U.S. include a variety of emission points for methane, VOC, and HAP, including wells, well sites, processing plants, compressor stations, storage equipment, and transmission and distribution lines. These emission points are located throughout much of the country with significant concentrations in particular geographic regions. For example, wells and processing plants are largely concentrated in the South Central, Midwest, and Southern California regions of the U.S., whereas natural gas compressor stations are located all over the country. Distribution lines to customers are frequently located within areas of high population density.

Implementing this rule may result in forgone reductions in ambient $PM_{2.5}$ and ozone concentrations in areas attaining and not attaining the National Ambient Air Quality Standards (NAAQS). Due to the high degree of variability in the responsiveness of ozone and $PM_{2.5}$ formation to VOC emission reductions, we are unable to determine how this rule might affect attainment status without modeling air quality changes.[33] Because the NAAQS RIAs also calculate ozone and $PM_{2.5}$ benefits, there are important differences worth noting in the design and analytical objectives of each impact analysis. The NAAQS RIAs illustrate the potential costs and benefits of attaining new nationwide air quality standards based on an array of emission

[33] The responsiveness of ozone and $PM_{2.5}$ formation is discussed in greater detail in sections 3.4.1 and 3.5.1 of this RIA.

control strategies for different sources.[34] By contrast, the emission reductions for implementation rules, including this rule, are generally from a specific class of well-characterized sources. In general, the EPA is more confident in the magnitude and location of the emission reductions for implementation rules rather than illustrative NAAQS analyses. Emission changes realized under these and other promulgated rules will ultimately be reflected in the baseline of future NAAQS analyses, which would affect the incremental costs and benefits associated with attaining future NAAQS.

[REF _Ref288132327 \h * MERGEFORMAT] shows the total increase in direct emissions, compared to the 2018 baseline, anticipated for this proposed rule across the regulatory options examined for 2019 through 2025. It is important to note that these emissions accrue at different spatial scales. HAP emissions increase exposure to carcinogens and other toxic pollutants primarily near the emission source. VOC emissions are precursors to secondary formation of $PM_{2.5}$ and ozone on a broader regional scale. Climate effects associated with long-lived greenhouse gases like methane generally do not depend on the location of the emission of the gas, and have global impacts. Methane is also a precursor to global background concentrations of ozone (Sarofim 2015). Section 2.4.3 describes the emission increases for the proposed option estimated in each year.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Total Direct Increases in Emissions Compared to the 2018 Baseline across Regulatory Options, 2019 through 2025

Pollutant	Option 1	Option 2 (Proposed)	Option 3
Methane (short tons)	0	200,000	280,000
VOC (short tons)	0	56,000	77,000
HAP (short tons)	0	2,100	2,900
Methane (metric tons)	0	180,000	250,000
Methane (million metric tons CO_2 Eq.)	0	4.5	6.2

[REF _Ref511208772 \h * MERGEFORMAT] shows the methane, VOC and HAP emissions increases for Option 2 and Option 3 for each year, compared to the 2018 baseline.

[34] NAAQS RIAs hypothesize, but do not predict, the control strategies States may choose to enact when implementing a NAAQS. The setting of a NAAQS does not directly result in costs or benefits, and as such, the NAAQS RIAs are merely illustrative and are not intended to be added to the costs and benefits of other regulations that result in specific costs of control and emission reductions. However, some costs and benefits estimated in this RIA may account for the same air quality improvements as estimated in an illustrative NAAQS RIA.

Option 1 is not included in this table, as there are no estimated changes in emissions under Option 1.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Annual Direct Increases in Methane, VOC and HAP Emissions Compared to the 2018 Baseline, Options 2 and 3, 2019 through 2025

Year	Option 2			Option 3		
	Methane (metric tons)	VOC	HAP	Methane (metric tons)	VOC	HAP
2019	15,000	4,700	180	21,000	6,400	240
2020	19,000	5,700	220	26,000	7,800	300
2021	22,000	6,800	260	30,000	9,300	350
2022	26,000	7,900	300	35,000	11,000	410
2023	30,000	9,100	340	41,000	12,000	470
2024	33,000	10,000	380	46,000	14,000	530
2025	37,000	11,000	430	51,000	16,000	590
Total	**180,000**	**56,000**	**2,100**	**250,000**	**77,000**	**2,900**

3.3 Methane Climate Effects and Valuation

Methane is the principal component of natural gas. Methane is also a potent greenhouse gas (GHG) that, once emitted into the atmosphere, absorbs terrestrial infrared radiation, which in turn contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form ozone, which also impacts global temperatures. Methane, in addition to other GHG emissions, contributes to warming of the atmosphere, which over time leads to increased air and ocean temperatures; changes in precipitation patterns; melting and thawing of global glaciers and ice sheets; increasingly severe weather events, such as hurricanes of greater intensity; and sea level rise, among other impacts.

According to the Intergovernmental Panel on Climate Change (IPCC) Fifth Assessment Report (AR5, 2013), changes in methane concentrations since 1750 contributed 0.48 W/m^2 of forcing, which is about 17 percent of all global forcing due to increases in anthropogenic GHG concentrations, and which makes methane the second leading long-lived climate forcer after CO_2. However, after accounting for changes in other greenhouse substances such as ozone and stratospheric water vapor due to chemical reactions of methane in the atmosphere, historical methane emissions were estimated to have contributed to 0.97 W/m^2 of forcing today, which is about 30 percent of the contemporaneous forcing due to historical greenhouse gas emissions.

The oil and natural gas sector emits significant amounts of methane. The public Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2014 (to be published April 15, 2016) estimates 2014 methane emissions from Petroleum and Natural Gas Systems (not including petroleum refineries and petroleum transportation) to be 232 MMt CO_2 Eq. In 2014, total methane emissions from the oil and natural gas industry represented 32 percent of the total methane emissions from all sources and account for about 3 percent of all CO_2 Eq. emissions in the U.S., with the combined petroleum and natural gas systems being the largest contributor to U.S. anthropogenic methane emissions (U.S. EPA, 2016c).

The 2016 NSPS OOOOa was expected to result in climate-related benefits by reducing methane emissions. The proposed changes would therefore forgo climate-related benefits associated with these emissions reductions as discussed above. To give a sense of the magnitude of the emissions increases presented in [REF _Ref445289124 \h], [REF _Ref288132327 \h], and [REF _Ref511208772 \h], the forgone methane reductions estimated for 2020 (0.47 million metric tons CO_2 Eq.) are equivalent to about 0.2 percent of the methane emissions for this sector reported in the U.S. GHGI for 2014 (about 232 million metric tons CO_2 Eq. are from petroleum and natural gas production and gas processing, transmission, and storage). Expected forgone emission reductions in 2025 (about 0.93 million metric tons CO_2 Eq.) are equivalent to around 0.4 percent of 2014 emissions. As it is expected that emissions from this sector would increase over time, the estimates compared against the 2014 emissions would likely overestimate the percent of total emissions in 2020 and 2025.

We estimate the forgone climate benefits from the proposal using an interim measure of the domestic social cost of methane (SC-CH_4). The SC-CH_4 is an estimate of the monetary value of impacts associated with marginal changes in CH_4 emissions in a given year. It includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity and human health, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. It is typically used to assess the avoided damages as a result of regulatory actions (i.e., benefits of rulemakings that lead to an incremental reduction in cumulative global CH_4 emissions). The SC-CH_4 estimates used in this analysis focus on the direct impacts of climate change that are anticipated to occur within U.S. borders.

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The SC-CH_4 estimates presented here are interim values developed under E.O. 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. E.O. 13783 directed agencies to ensure that estimates of the social cost of greenhouse gases used in regulatory analyses "are based on the best available science and economics" and are consistent with the guidance contained in OMB Circular A-4, "including with respect to the consideration of domestic versus international impacts and the consideration of appropriate discount rates" (E.O. 13783, Section 5(c)). In addition, E.O. 13783 withdrew the technical support documents (TSDs) and the August 2016 Addendum to these TSDs describing the global social cost of greenhouse gas 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 (IWG) that included the EPA and other executive branch entities and were used in the 2016 NSPS RIA.

Regarding the two analytical considerations highlighted in E.O. 13783 – how best to consider domestic versus international impacts and appropriate discount rates – current guidance in OMB Circular A-4 is as follows. Circular A-4 states that analysis of economically significant proposed and final regulations "should focus on benefits and costs that accrue to citizens and residents of the United States." Though this action is not economically significant as defined in E.O. 12866, section 3(f)(1), we follow this guidance by adopting a domestic perspective in our central analysis. Regarding discount rates, Circular A-4 states that regulatory analyses "should provide estimates of net benefits using both 3 percent and 7 percent." The 7 percent rate is intended to represent the average before-tax rate of return to private capital in the U.S. economy. The 3 percent rate is intended to reflect the rate at which society discounts future consumption, which is particularly relevant if a regulation is expected to affect private consumption directly. The EPA follows this guidance below by presenting estimates based on both 3 and 7 percent discount rates in the main analysis. See the Appendix for a discussion the modeling steps involved in estimating the domestic SC-CH_4 estimates based on these discount rates.

The SC-CH_4 estimates developed under E.O. 13783 will be used in regulatory analysis until improved domestic estimates can be developed, which will take into consideration the

recent recommendations from the National Academies of Sciences, Engineering, and Medicine[35] for a comprehensive update to the current methodology to ensure that the social cost of greenhouse gas estimates reflect the best available science. While the Academies' review focused on the methodology to estimate the social cost of carbon (SC-CO_2), the recommendations on how to update many of the underlying modeling assumptions also pertain to the SC-CH_4 estimates since the framework used to estimate SC-CH_4 is the same as that used for SC-CO_2.

[REF _Ref506545898 \h] presents the average domestic SC-CH_4 estimates across all the model runs for each discount rate for emissions occurring in 2019 to 2025. As with the global SC-CH_4 estimates, the domestic SC-CH_4 increases over time because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed in response to greater climatic change, and because GDP is growing over time and many damage categories are modeled as proportional to gross GDP.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Interim Domestic Social Cost of CH_4, 2019-2025 (in 2016$ per metric ton CH_4)*

	Discount Rate and Statistic	
Year	7% Average	3% Average
2019	$53	$170
2020	55	180
2021	58	180
2022	60	190
2023	63	190
2024	65	200
2025	68	200

* SC-CH_4 values are stated in $/metric ton CH_4 and rounded to two significant digits. The estimates vary depending on the year of CH_4 emissions and are defined in real terms, i.e., adjusted for inflation using the GDP implicit price deflator.

The SC-CH_4 estimates in [REF _Ref508112417 \h] are used to monetize the forgone domestic climate benefits across regulatory options under consideration. Forecasted increases in methane emissions in a given year, expected as a result of the regulatory action, are multiplied by the SC-CH_4 estimate for that year. Under the proposed option (Option 2), the forgone climate benefits vary by discount rate and year, and range from about $0.81 million to approximately

[35] See National Academies of Sciences, Engineering, and Medicine, Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide, Washington, D.C., January 2017. http://www.nap.edu/catalog/24651/valuing-climate-changes-updating-estimation-of-the-social-cost-of

$2.5 million under a 7 percent discount rate, and from about $2.6 million to approximately $7.6 million under a 3 percent discount rate, as seen in [REF _Ref508111836 \h].

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Estimated Forgone Domestic Climate Benefits, 2019-2025 (millions, 2016$)

Year	7 percent	3 Percent
2019	$0.81	$2.6
2020	$1.0	$3.3
2021	$1.3	$4.0
2022	$1.6	$4.8
2023	$1.9	$5.7
2024	$2.2	$6.6
2025	$2.5	$7.6

[REF _Ref508112235 \h] shows the forgone domestic climate benefits in each year discounted to 2016 using a 3 or 7 percent discount rate. The table also shows the PV and the EAV for the 2019 through 2025-time horizon under each discount rate. The PV of forgone benefits under a 7 percent discount rate is about $7.2 million, with an EAV of about $1.2 million per year. The PV of forgone benefits under a 3 percent discount rate of $28 million, with an EAV of about $4.4 million per year.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Discounted Forgone Domestic Climate Benefits, PV and EAV (millions, 2016$)*

Year	7 percent	3 Percent
2019	$0.66	$2.4
2020	$0.78	$2.9
2021	$0.91	$3.5
2022	$1.0	$4.0
2023	$1.2	$4.6
2024	$1.3	$5.2
2025	$1.4	$5.8
PV	**$7.2**	**$28**
EAV	**$1.2**	**$4.4**

*The forgone domestic climate benefits in each year are discounted to 2016.

[REF _Ref508112282 \h] shows the total increase in emissions over the 2019 through 2025-time horizon as well as the PV and EAV of the forgone domestic climate benefits under 3 percent and 7 percent discount rates. This table shows how the different values of the climate benefits, as seen in [REF _Ref508112417 \h], affect the PV and EAV of each option. The affected sources in Option 1 are all related to certification requirements, which do not affect emissions. The number of affected sources in Option 3 is slightly larger than under Option 2,

which leads the increase in emissions, as well as the forgone benefits, to be slightly larger as well.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Estimated Forgone Domestic Climate Benefits of the Proposal* (in millions, 2016$)

	Option 1	Option 2 (proposed)	Option 3
Total Increase in Emission, 2019-2025			
Forgone CH_4 reductions (metric tonnes)	0	180,000	250,000
Forgone CH_4 reductions (million metric tonnes of CO_2 Eq.)	0	4.5	6.2
Forgone Domestic Climate Benefits (million 2016$)			
PV			
3% (average)	$0	$28	$39
7% (average)	$0	$7.2	$9.9
EAV			
3% (average)	$0	$4.4	$6.1
7% (average)	$0	$1.2	$1.7

*The SC-CH_4 values are dollar-year and emissions-year specific. SC-CH_4 values represent only a partial accounting of climate impacts.

The limitations and uncertainties associated with the global SC-CH_4 estimates, which were discussed in detail in the 2016 NSPS RIA, likewise apply to the forgone domestic SC-CH_4 estimates presented in this analysis.[36] Some uncertainties are captured within the analysis, as discussed in detail in the Appendix while other areas of uncertainty have not yet been quantified in a way that can be modeled. For example, as with the methodology used to calculate SC-CO_2 estimates, limitations include incomplete or inadequate representation in the integrated assessment models of several important factors: catastrophic and non-catastrophic impacts, adaptation and technological change, inter-regional and inter-sectoral linkages, uncertainty in the extrapolation of damages to high temperatures, and the relationship between the discount rate and uncertainty in economic growth over long time horizons. The science incorporated into these

[36] The SC-CH_4 estimates presented in the 2016 NSPS RIA are the same as the SC-CH_4 estimates presented in EPA-HQ-OAR-2015-0827-5886, "Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide (August 2016)", except the estimates in the 2016 NSPS RIA were adjusted to 2012$. The estimates published in the 2016 NSPS RIA were labeled as "Marten *et al.* (2014)" estimates. In addition, EPA-HQ-OAR-2015-0827-5886 provides a detailed discussion of the limitations and uncertainties associated with the SC-GHG estimates.

models understandably lags behind the most recent research, and the limited amount of research linking climate impacts to economic damages makes the modeling exercise even more difficult.

There are several limitations specific to the estimation of SC-CH_4. For example, the SC-CH_4 estimates do not reflect updates from the IPCC regarding atmospheric and radiative efficacy.[37] Another limitation is that the SC-CH_4 estimates do not account for the direct health and welfare impacts associated with tropospheric ozone produced by methane (see the 2016 NSPS RIA for further discussion). In addition, the SC-CH_4 estimates do not reflect that methane emissions lead to a reduction in atmospheric oxidants, like hydroxyl radicals, nor do they account for impacts associated with CO_2 produced from methane oxidizing in the atmosphere. See EPA-HQ-OAR-2015-0827-5886 for more detailed discussion about the limitations specific to the estimation of SC-CH_4. These individual limitations and uncertainties do not all work in the same direction in terms of their influence on the SC-CH_4 estimates. In accordance with guidance in OMB Circular A-4 on the treatment of uncertainty, the Appendix provides a detailed discussion of the ways in which the modeling underlying the development of the SC-CH_4 estimates used in this analysis addresses quantified sources of uncertainty, and presents a sensitivity analysis to show consideration of the uncertainty surrounding discount rates over long time horizons.

Recognizing the limitations and uncertainties associated with estimating the social cost of greenhouse gases, the research community has continued to explore opportunities to improve estimates of SC-CO_2 and other greenhouse gases. Notably, the National Academies of Sciences, Engineering, and Medicine conducted a multi-discipline, multi-year assessment to examine potential approaches, along with their relative merits and challenges, for a comprehensive update to the IWG methodology. The task was to ensure that the SC-CO_2 estimates that are used in Federal analyses reflect the best available science, focusing on issues related to the choice of models and damage functions, climate science modeling assumptions, socioeconomic and emissions scenarios, presentation of uncertainty, and discounting. In January 2017, the Academies released their final report, *Valuing Climate Damages: Updating Estimation of the*

[37] The SC-CH_4 estimates used in the 2016 NSPS RIA served as the starting point to calculate the interim domestic estimates presented in this RIA. The 2016 NSPS RIA SC-CH_4 estimates were calculated in 2014 using atmospheric and radiative efficacy values that have since been updated by the IPCC

Social Cost of Carbon Dioxide,[38] and recommended specific criteria for future updates to the SC-CO_2 estimates, a modeling framework to satisfy the specified criteria, and both near-term updates and longer-term research needs pertaining to various components of the estimation process (National Academies 2017). Since the framework used to estimate SC-CH_4 is the same as that used for SC-CO_2, the Academies' recommendations on how to update many of the underlying modeling assumptions also apply to the SC-CH_4 estimates.

The Academies' report also discussed the challenges in developing domestic SC-CO_2 estimates, noting that current IAMs do not model all relevant regional interactions—e.g., how climate change impacts in other regions of the world could affect the United States, through pathways such as global migration, economic destabilization, and political destabilization. The Academies concluded that it "is important to consider what constitutes a domestic impact in the case of a global pollutant that could have international implications that impact the United States. More thoroughly estimating a domestic SC-CO_2 would therefore need to consider the potential implications of climate impacts on, and actions by, other countries, which also have impacts on the United States." (National Academies 2017, pg 12-13). This challenge is equally applicable to the estimation of a domestic SC-CH_4.

In addition to requiring reporting of domestic impacts, Circular A-4 states that when an agency "evaluate[s] a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately" (page 15). This guidance is relevant to the valuation of damages from methane and other GHGs, given that GHGs contribute to damages around the world independent of the country in which they are emitted. Therefore, in accordance with this guidance in OMB Circular A-4, the Appendix presents the forgone global climate benefits from the proposal using global SC-CH_4 estimates based on both 3 and 7 percent discount rates. Note that the EPA did not quantitatively project the full impact of the 2016 NSPS OOOOa on international trade and the location of production, so it is not possible to present analogous estimates of global cost savings resulting from the proposed action. However, to the

[38] National Academies of Sciences, Engineering, and Medicine. 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide.* National Academies Press. Washington, DC Available at <https://www.nap.edu/catalog/24651/valuing-climate-damages-updating-estimation-of-the-social-cost-of> Accessed May 30, 2017.

extent that affected firms have some foreign ownership, some of the cost savings accruing to entities outside U.S. borders is captured in the compliance cost savings presented in this RIA.

3.4 VOC as an Ozone Precursor

This rulemaking may forgo emission reductions of VOC, which are a precursor to ozone. Ozone is not emitted directly into the air, but is created when its two primary components, volatile organic compounds (VOC) and oxides of nitrogen (NO_x), react in the atmosphere in the presence of sunlight. In urban areas, compounds representing all classes of VOC are important for ozone formation, but biogenic VOC emitted from vegetation tend to be more important compounds in non-urban vegetated areas (U.S. EPA, 2013). Forgone emission reductions may increase ozone formation, human exposure to ozone, and the incidence of ozone-related health effects. However, we have not quantified the ozone-related forgone benefits in this analysis due to the complex non-linear chemistry of ozone formation, which introduces uncertainty to the development and application of a benefit-per-ton estimate, particularly for sectors with substantial new growth. In addition, the impact of forgone VOC emission reductions is spatially heterogeneous and highly dependent on local air chemistry. Urban areas with a high population concentration are often VOC-limited, which means that ozone is most effectively reduced by lowering VOC. Rural areas and downwind suburban areas are often NO_X-limited, which means that ozone concentrations are most effectively reduced by lowering NO_X emissions, rather than lowering emissions of VOC. Between these areas, ozone is relatively insensitive to marginal changes in both NO_X and VOC.

Due to data limitations regarding potential locations of new and modified sources affected by this rulemaking, we did not perform air quality modeling for this rule needed to quantify the forgone ozone benefits associated with forgone VOC emission reductions. Due to the high degree of variability in the responsiveness of ozone formation to VOC emissions and data limitations regarding the location of new and modified well sites, we are unable to estimate the effect that forgone VOC emission reductions will have on ambient ozone concentrations without air quality modeling.

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3.4.1 Ozone Health Effects

Human exposure to ambient ozone concentrations is associated with adverse health effects, including premature mortality and cases of respiratory morbidity (U.S. EPA, 2010a). Researchers have associated ozone exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2013). When adequate data and resources are available, the EPA has generally quantified several health effects associated with exposure to ozone (e.g., U.S. EPA, 2010a; U.S. EPA, 2011a). These health effects include: respiratory morbidity, such as asthma attacks; hospital and emergency department visits; lost school days; and premature mortality. The scientific literature is also suggestive that exposure to ozone is also associated with chronic respiratory damage and premature aging of the lungs.

EPA has previously estimated the ozone-related benefits of reducing VOC emissions from the industrial boiler sector (U.S. EPA, 2011b)[39] and in the RIA for the proposed Ozone NAAQS (U.S. EPA, 2014b). While the benefit-per-ton estimates used to quantify impacts for those rules may provide useful context, the geographic distribution of VOC emissions from the oil and natural gas sector is not consistent with emissions modeled in either analysis. Therefore, we do not believe that those estimates are representative of the monetized forgone benefits of this rule, even as a bounding exercise.

3.4.2 Ozone Vegetation Effects

Exposure to ozone has been found to be associated with a wide array of vegetation and ecosystem effects in the published literature (U.S. EPA, 2013). Sensitivity to ozone is highly variable across species, with over 66 vegetation species identified as "ozone-sensitive", many of which occur in state and national parks and forests. These effects include those that damage to, or impairment of, the intended use of the plant or ecosystem. Such effects are considered adverse to public welfare and can include reduced growth and/or biomass production in sensitive trees, reduced yield and quality of crops, visible foliar injury, changed to species composition, and changes in ecosystems and associated ecosystem services.

[39] While the EPA has estimated the ozone benefits for many scenarios, most of those scenarios also reduce NO_2 emissions, which make it difficult to isolate the benefits attributable to VOC reductions.

3.4.3 Ozone Climate Effects

Ozone is a well-known short-lived climate forcing greenhouse gas (GHG) (U.S. EPA, 2013). Stratospheric ozone (the upper ozone layer) is beneficial because it protects life on Earth from the sun's harmful ultraviolet (UV) radiation. In contrast, tropospheric ozone (ozone in the lower atmosphere) is a harmful air pollutant that adversely affects human health and the environment and contributes significantly to regional and global climate change. Due to its short atmospheric lifetime, tropospheric ozone concentrations exhibit large spatial and temporal variability (U.S. EPA, 2009b). The IPCC AR5 estimated that the contribution to current warming levels of increased tropospheric ozone concentrations resulting from human methane, NOx, and VOC emissions was 0.5 W/m^2, or about 30 percent as large a warming influence as elevated CO_2 concentrations. This quantifiable influence of ground level ozone on climate leads to increases in global surface temperature and changes in hydrological cycles.

3.5 VOC as a $PM_{2.5}$ Precursor

This rulemaking may forgo emission reductions of VOC, which are a precursor to $PM_{2.5}$, thus possibly increasing human exposure to $PM_{2.5}$ and the incidence of $PM_{2.5}$-related health effects. Most VOC emitted are oxidized to CO_2 rather than to PM, but a portion of VOC emission contributes to ambient $PM_{2.5}$ levels as organic carbon aerosols (U.S. EPA, 2009a). Analysis of organic carbon measurements suggest only a fraction of secondarily formed organic carbon aerosols are of anthropogenic origin. The current state of the science of secondary organic carbon aerosol formation indicates that anthropogenic VOC contribution to secondary organic carbon aerosol is often lower than the biogenic (natural) contribution. Given that a fraction of secondarily formed organic carbon aerosols is from anthropogenic VOC emissions and the extremely small amount of VOC emissions from this sector relative to the entire VOC inventory, it is unlikely this sector has a large contribution to ambient secondary organic carbon aerosols. Photochemical models typically estimate secondary organic carbon from anthropogenic VOC emissions to be less than 0.1 $\mu g/m^3$. Therefore, we have not quantified the forgone $PM_{2.5}$-related benefits in this analysis.

Due to data limitations regarding potential locations of new and modified sources affected by this rulemaking, we were unable to perform air quality modeling of the ambient

$PM_{2.5}$ impacts of the proposed rule, which is needed to quantify forgone $PM_{2.5}$ benefits associated with forgone VOC emission reductions for this rule. Due to the high degree of variability in the responsiveness of $PM_{2.5}$ formation to VOC emission reductions, we are unable to estimate the effect that reducing VOC will have on ambient $PM_{2.5}$ levels without air quality modeling. However, we provide the discussion below for context regarding findings from previous modeling.

3.5.1 $PM_{2.5}$ Health Effects

Increasing VOC emissions would increase secondary $PM_{2.5}$ formation, and, thus, the incidence of $PM_{2.5}$-related health effects. Increasing exposure to $PM_{2.5}$ is associated with significant human health detriments, including mortality and respiratory morbidity. Researchers have associated $PM_{2.5}$ exposure with adverse health effects in numerous toxicological, clinical and epidemiological studies (U.S. EPA, 2009a). These health effects include premature death in people with heart or lung disease, nonfatal heart attacks, irregular heartbeat, aggravated asthma, decreased lung function, and increased respiratory symptoms, such as irritation of the airways, coughing, or difficulty breathing (U.S. EPA, 2009a). These health effects result in hospital and ER visits, lost work days, and restricted activity days. When adequate data and resources are available, the EPA has quantified the health effects associated with exposure to $PM_{2.5}$ (e.g., U.S. EPA (2011g).

When the EPA quantifies $PM_{2.5}$-related benefits, the agency assumes that all fine particles, regardless of their chemical composition, are equally potent in causing premature mortality because the scientific evidence is not yet sufficient to allow differentiation of effect estimates by particle type (U.S. EPA, 2009a). Based on our review of the current body of scientific literature, the EPA estimates PM-related premature mortality without applying an assumed concentration threshold. This decision is supported by the data, which are quite consistent in showing effects down to the lowest measured levels of $PM_{2.5}$ in the underlying epidemiology studies.

Fann, Fulcher, and Hubbell (2009) examined how the monetized benefit-per-ton estimates of reducing ambient $PM_{2.5}$ varies by the location of the emission reduction, the type of source emitting the precursor, and the specific precursor controlled. This study employed a

reduced-form air quality model to estimate changes in ambient $PM_{2.5}$ from reducing 12 different combinations of precursor emissions and emission sources, including reducing directly emitted carbonaceous particles, nitrogen oxides, sulfur oxides, ammonia, and VOCs for nine urban areas and nationwide. However, while these ranges of benefit-per-ton estimates provide general context, the geographic distribution of VOC emissions from the oil and natural gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship between VOC emissions and $PM_{2.5}$, these factors have lead the EPA to conclude that the available VOC benefit per ton estimates are not appropriate for use in monetizing the $PM_{2.5}$ benefits of this rule, even as a bounding exercise.

3.5.2 Organic PM Welfare Effects

According to the previous residual risk assessment that the EPA performed for this sector (U.S. EPA, 2012a), persistent and bioaccumulative HAP reported as emissions from oil and natural gas operations include polycyclic organic matter (POM). POM defines a broad class of compounds that includes polycyclic aromatic hydrocarbon compounds (PAHs). Several significant ecological effects are associated with the deposition of organic particles, including persistent organic pollutants, and PAHs (U.S. EPA, 2009a). This summary is from section 6.6.1 of the 2012 PM NAAQS RIA (U.S. EPA, 2012c).

PAHs can accumulate in sediments and bioaccumulate in freshwater, flora, and fauna. The uptake of organics depends on the plant species, site of deposition, physical and chemical properties of the organic compound and prevailing environmental conditions (U.S. EPA, 2009a). PAHs can accumulate to high enough concentrations in some coastal environments to pose an environmental health threat that includes cancer in fish populations, toxicity to organisms living in the sediment and risks to those (e.g., migratory birds) that consume these organisms. Atmospheric deposition of particles is thought to be the major source of PAHs to the sediments of coastal areas of the U.S. Deposition of PM to surfaces in urban settings increases the metal and organic component of storm water runoff. This atmospherically-associated pollutant burden can then be toxic to aquatic biota. The contribution of atmospherically deposited PAHs to

aquatic food webs was demonstrated in high elevation mountain lakes with no other anthropogenic contaminant sources.

The Western Airborne Contaminants Assessment Project (WACAP) is the most comprehensive database available on contaminant transport and the effects of PM deposition on sensitive ecosystems in the Western U.S. (Landers *et al.*, 2008). In this project, the transport, fate, and ecological impacts of anthropogenic contaminants from atmospheric sources were assessed from 2002 to 2007 in seven ecosystem components (air, snow, water, sediment, lichen, conifer needles, and fish) in eight core national parks. The study concluded that bioaccumulation of semi-volatile organic compounds occurred throughout park ecosystems, that an elevational gradient in PM deposition exists with greater accumulation in higher altitude areas, and that contaminants accumulate in proximity to individual agriculture and industry sources, which is counter to the original working hypothesis that most of the contaminants would originate from Eastern Europe and Asia.

3.5.3 Visibility Effects

Increasing secondary formation of $PM_{2.5}$ from VOC emissions could reduce visibility throughout the U.S. Fine particles with significant light-extinction efficiencies include sulfates, nitrates, organic carbon, elemental carbon, and soil (Sisler, 1996). Suspended particles and gases degrade visibility by scattering and absorbing light. Higher visibility impairment levels in the East are due to higher concentrations of fine particles, particularly sulfates, and higher average relative humidity levels. Visibility impairment has a direct impact on people's enjoyment of daily activities and their overall sense of wellbeing. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities. Previous analyses (U.S. EPA, 2006b; U.S. EPA, 2011a; U.S. EPA, 2011g; U.S. EPA, 2012c) show that visibility benefits are a significant welfare benefit category. However, without air quality modeling, we are unable to estimate forgone visibility related benefits, nor are we able to determine whether VOC emission would be likely to have a significant impact on visibility in urban areas or Class I areas.

3.6 Hazardous Air Pollutants (HAP)

When looking at exposures from all air toxic sources of outdoor origin across the U.S., we see that emissions declined by approximately 60 percent since 1990. However, despite this decline, the 2011 National-Scale Air Toxics Assessment (NATA) predicts that most Americans are exposed to ambient concentrations of air toxics at levels that have the potential to cause adverse health effects (U.S. EPA, 2015).[40] The levels of air toxics to which people are exposed vary depending on where they live and work and the kinds of activities in which they engage. In order to identify and prioritize air toxics, emission source types and locations that are of greatest potential concern, the EPA conducts the NATA.[41] The most recent NATA was conducted for calendar year 2011 and was released in December 2015. NATA includes four steps:

1) Compiling a national emissions inventory of air toxics emissions from outdoor sources;

2) Estimating ambient concentrations of air toxics across the U.S. utilizing dispersion models;

3) Estimating population exposures across the U.S. utilizing exposure models; and

4) Characterizing potential public health risk due to inhalation of air toxics including both cancer and noncancer effects.

Based on the 2011 NATA, the EPA estimates that less than 1 percent of census tracts nationwide have increased cancer risks greater than 100 in a million. The average national cancer risk is about 40 in a million. Nationwide, the key pollutants that contribute most to the overall cancer risks are formaldehyde and benzene.[42,43] Secondary formation (e.g., formaldehyde forming from other emitted pollutants) was the largest contributor to cancer risks, while

[40] The 2011 NATA is available on the Internet at http://www.epa.gov/national-air-toxics-assessment/2011-national-air-toxics-assessment.

[41] The NATA modeling framework has a number of limitations that prevent its use as the sole basis for setting regulatory standards. These limitations and uncertainties are discussed on the 2011 NATA website. Even so, this modeling framework is very useful in identifying air toxic pollutants and sources of greatest concern, setting regulatory priorities, and informing the decision making process. U.S. EPA. (2015) 2011 National-Scale Air Toxics Assessment. <http://www.epa.gov/national-air-toxics-assessment/2011-national-air-toxics-assessment>.

[42] Details on EPA's approach to characterization of cancer risks and uncertainties associated with the 2011 NATA risk estimates can be found at <http://www.epa.gov/national-air-toxics-assessment/nata-limitations>.

[43] Details about the overall confidence of certainty ranking of the individual pieces of NATA assessments including both quantitative (e.g., model-to-monitor ratios) and qualitative (e.g., quality of data, review of emission inventories) judgments can be found at <http://www.epa.gov/national-air-toxics-assessment/nata-limitations>.

stationary, mobile, biogenics, and background sources contribute lesser amounts to the remaining cancer risk.

Noncancer health effects can result from chronic,[44] subchronic,[45] or acute[46] inhalation exposure to air toxics, and include neurological, cardiovascular, liver, kidney, and respiratory effects as well as effects on the immune and reproductive systems. According to the 2011 NATA, about 80 percent of the U.S. population was exposed to an average chronic concentration of air toxics that has the potential for adverse noncancer respiratory health effects. Results from the 2011 NATA indicate that acrolein is the primary driver for noncancer respiratory risk.

[REF _Ref445293782 \h] and [REF _Ref445293794 \h] depict the 2011 NATA estimated census tract-level carcinogenic risk and noncancer respiratory hazard from the assessment. It is important to note that increases in HAP emissions may not necessarily translate into significant increases in health risk because toxicity varies by pollutant, and exposures may or may not exceed levels of concern. For example, acetaldehyde mass emissions were more than seventeen times acrolein mass emissions on a national basis in the EPA's 2011 National Emissions Inventory (NEI). However, the Integrated Risk Information System (IRIS) reference concentration (RfC) for acrolein is considerably lower than that for acetaldehyde. This results in 2011 NATA estimates of nationwide chronic respiratory noncancer risks from acrolein being over three times that of acetaldehyde.[47] Thus, it is important to account for the toxicity and exposure, as well as the mass of the targeted emissions.

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[44] Chronic exposure is defined in the glossary of the Integrated Risk Information System (IRIS) database (<http://www.epa.gov/iris>) as repeated exposure by the oral, dermal, or inhalation route for more than approximately 10 of the life span in humans (more than approximately 90 days to 2 years in typically used laboratory animal species).

[45] Defined in the IRIS database as repeated exposure by the oral, dermal, or inhalation route for more than 30 days, up to approximately 10 of the life span in humans (more than 30 days up to approximately 90 days in typically used laboratory animal species).

[46] Defined in the IRIS database as exposure by the oral, dermal, or inhalation route for 24 hours or less.

[47] Details on the derivation of IRIS values and available supporting documentation for individual chemicals (as well as chemical values comparisons) can be found at <http://www.epa.gov/iris>.

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Figure 3-[SEQ Figure * ARABIC \s 1] 2011 NATA Model Estimated Census Tract Carcinogenic Risk from HAP Exposure from All Outdoor Sources based on the 2011 National Emissions Inventory

Figure 3-[SEQ Figure * ARABIC \s 1] 2011 NATA Model Estimated Census Tract Noncancer (Respiratory) Risk from HAP Exposure from All Outdoor Sources based on the 2011 National Emissions Inventory

Due to methodology and data limitations, we were unable to estimate the forgone benefits associated with the hazardous air pollutant emissions that would be forgone as a result of this rule. In a few previous analyses of the benefits of reductions in HAP, the EPA has quantified the benefits of potential reductions in the incidences of cancer and noncancer risk (e.g., U.S. EPA, 1995). In those analyses, the EPA relied on unit risk factors (URF) and reference concentrations (RfC) developed through risk assessment procedures. The URF is a quantitative estimate of the carcinogenic potency of a pollutant, often expressed as the probability of contracting cancer from a 70-year lifetime continuous exposure to a concentration of one $\mu g/m^3$ of a pollutant. These URFs are designed to be conservative, and as such, are more likely to represent the high end of

the distribution of risk rather than a best or most likely estimate of risk. An RfC is an estimate (with uncertainty spanning perhaps an order of magnitude) of a continuous inhalation exposure to the human population (including sensitive subgroups) that is likely to be without an appreciable risk of deleterious noncancer health effects during a lifetime. As the purpose of a forgone benefit analysis is to describe the benefits most likely to result from a forgone reduction in pollution, use of high-end, conservative risk estimates would overestimate the forgone benefits of the regulation. While we used high-end risk estimates in past analyses, advice from the EPA's Science Advisory Board (SAB) recommended that we avoid using high-end estimates in benefit analyses (U.S. EPA-SAB, 2002). Since that time, the EPA has continued to develop better methods for analyzing the benefits of reductions in HAP.

As part of the second prospective analysis of the benefits and costs of the Clean Air Act (U.S. EPA, 2011a), the EPA conducted a case study analysis of the health effects associated with reducing exposure to benzene in Houston from implementation of the Clean Air Act (IEc, 2009). While reviewing the draft report, the EPA's Advisory Council on Clean Air Compliance Analysis concluded that "the challenges for assessing progress in health improvement as a result of reductions in emissions of hazardous air pollutants (HAP) are daunting...due to a lack of exposure-response functions, uncertainties in emissions inventories and background levels, the difficulty of extrapolating risk estimates to low doses and the challenges of tracking health progress for diseases, such as cancer, that have long latency periods" (U.S. EPA-SAB, 2008).

In 2009, the EPA convened a workshop to address the inherent complexities, limitations, and uncertainties in current methods to quantify the benefits of reducing HAP. Recommendations from this workshop included identifying research priorities, focusing on susceptible and vulnerable populations, and improving dose-response relationships (Gwinn *et al.*, 2011).

In summary, monetization of the forgone benefits of reductions in cancer incidences requires several important inputs, including central estimates of cancer risks, estimates of exposure to carcinogenic HAP, and estimates of the value of an avoided case of cancer (fatal and non-fatal). Due to methodology and data limitations, we did not attempt to monetize the forgone health benefits of forgone reductions in HAP in this analysis. Instead, we are providing a qualitative analysis of the health effects associated with the HAP anticipated to be forgone by

this rule. The EPA remains committed to improving methods for estimating HAP benefits by continuing to explore additional concepts of benefits, including changes in the distribution of risk.

Available emissions data show that several different HAP are emitted from oil and natural gas operations, either from equipment leaks, processing, compressing, transmission and distribution, or storage tanks. Emissions of eight HAP make up a large percentage of the total HAP emissions by mass from the oil and natural gas sector: toluene, hexane, benzene, xylenes (mixed), ethylene glycol, methanol, ethyl benzene, and 2,2,4-trimethylpentane (U.S. EPA, 2012a). In the subsequent sections, we describe the health effects associated with the main HAP of concern from the oil and natural gas sector: benzene, toluene, carbonyl sulfide, ethyl benzene, mixed xylenes, and n-hexane. This rule is anticipated to result an increase of a total of 2,100 tons of HAP emissions over 2019 through 2025. With the data available, it was not possible to estimate the change in emissions of each individual HAP.

3.6.1 Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.[48,49,50] EPA states in its IRIS database that data indicate a causal relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human

[48] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Benzene. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at: <http://www.epa.gov/iris/subst/0276.htm>.

[49] International Agency for Research on Cancer, IARC monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Some industrial chemicals and dyestuffs, International Agency for Research on Cancer, World Health Organization, Lyon, France, p. 345-389, 1982.

[50] Irons, R.D.; Stillman, W.S.; Colagiovanni, D.B.; Henry, V.A. (1992) Synergistic action of the benzene metabolite hydroquinone on myelopoietic stimulating activity of granulocyte/macrophage colony-stimulating factor in vitro, Proc. Natl. Acad. Sci. 89:3691-3695.

Services has characterized benzene as a known human carcinogen.[51,52] A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[53,54]

3.6.2 Toluene[55]

Under the 2005 Guidelines for Carcinogen Risk Assessment, there is inadequate information to assess the carcinogenic potential of toluene because studies of humans chronically exposed to toluene are inconclusive, toluene was not carcinogenic in adequate inhalation cancer bioassays of rats and mice exposed for life, and increased incidences of mammary cancer and leukemia were reported in a lifetime rat oral bioassay.

The central nervous system (CNS) is the primary target for toluene toxicity in both humans and animals for acute and chronic exposures. CNS dysfunction (which is often reversible) and narcosis have been frequently observed in humans acutely exposed to low or moderate levels of toluene by inhalation: symptoms include fatigue, sleepiness, headaches, and nausea. Central nervous system depression has been reported to occur in chronic abusers exposed to high levels of toluene. Symptoms include ataxia, tremors, cerebral atrophy, nystagmus (involuntary eye movements), and impaired speech, hearing, and vision. Chronic inhalation exposure of humans to toluene also causes irritation of the upper respiratory tract, eye irritation, dizziness, headaches, and difficulty with sleep.

Human studies have also reported developmental effects, such as CNS dysfunction, attention deficits, and minor craniofacial and limb anomalies, in the children of women who abused toluene during pregnancy. A substantial database examining the effects of toluene in

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[51] International Agency for Research on Cancer (IARC). 1987. Monographs on the evaluation of carcinogenic risk of chemicals to humans, Volume 29, Supplement 7, Some industrial chemicals and dyestuffs, World Health Organization, Lyon, France.

[52] U.S. Department of Health and Human Services National Toxicology Program 11th Report on Carcinogens available at: <http://ntp.niehs.nih.gov/go/16183>.

[53] Aksoy, M. (1989). Hematotoxicity and carcinogenicity of benzene. Environ. Health Perspect. 82: 193-197.

[54] Goldstein, B.D. (1988). Benzene toxicity. Occupational medicine. State of the Art Reviews. 3: 541-554.

[55] All health effects language for this section came from: U.S. EPA. 2005. "Full IRIS Summary for Toluene (CASRN 108-88-3)" Environmental Protection Agency, Integrated Risk Information System (IRIS), Office of Health and Environmental Assessment, Environmental Criteria and Assessment Office, Cincinnati, OH. Available on the Internet at <http://www.epa.gov/iris/subst/0118.htm>.

subchronic and chronic occupationally exposed humans exists. The weight of evidence from these studies indicates neurological effects (i.e., impaired color vision, impaired hearing, decreased performance in neurobehavioral analysis, changes in motor and sensory nerve conduction velocity, headache, and dizziness) as the most sensitive endpoint.

3.6.3 Carbonyl Sulfide

Limited information is available on the health effects of carbonyl sulfide. Acute (short-term) inhalation of high concentrations of carbonyl sulfide may cause narcotic effects and irritate the eyes and skin in humans.[56] No information is available on the chronic (long-term), reproductive, developmental, or carcinogenic effects of carbonyl sulfide in humans. Carbonyl sulfide has not undergone a complete evaluation and determination under U.S. EPA's IRIS program for evidence of human carcinogenic potential.[57]

3.6.4 Ethylbenzene

Ethylbenzene is a major industrial chemical produced by alkylation of benzene. The pure chemical is used almost exclusively for styrene production. It is also a constituent of crude petroleum and is found in gasoline and diesel fuels. Acute (short-term) exposure to ethylbenzene in humans results in respiratory effects such as throat irritation and chest constriction, and irritation of the eyes, and neurological effects such as dizziness. Chronic (long-term) exposure of humans to ethylbenzene may cause eye and lung irritation, with possible adverse effects on the blood. Animal studies have reported effects on the blood, liver, and kidneys and endocrine system from chronic inhalation exposure to ethylbenzene. No information is available on the developmental or reproductive effects of ethylbenzene in humans, but animal studies have reported developmental effects, including birth defects in animals exposed via inhalation. Studies in rodents reported increases in the percentage of animals with tumors of the nasal and oral

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[56] Hazardous Substances Data Bank (HSDB), online database. US National Library of Medicine, Toxicology Data Network, available online at http://toxnet.nlm.nih.gov/. Carbonyl health effects summary available at <http://toxnet.nlm.nih.gov/cgi-bin/sis/search/r?dbs+hsdb:@term+@rn+@rel+463-58-1>.

[57] U.S. Environmental Protection Agency (U.S. EPA). 2000. Integrated Risk Information System File for Carbonyl Sulfide. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at <http://www.epa.gov/iris/subst/0617.htm>.

cavities in male and female rats exposed to ethylbenzene via the oral route.[58,59] The reports of these studies lacked detailed information on the incidence of specific tumors, statistical analysis, survival data, and information on historical controls, thus the results of these studies were considered inconclusive by the International Agency for Research on Cancer (IARC, 2000) and the National Toxicology Program (NTP).[60,61] The NTP (1999) carried out a chronic inhalation bioassay in mice and rats and found clear evidence of carcinogenic activity in male rats and some evidence in female rats, based on increased incidences of renal tubule adenoma or carcinoma in male rats and renal tubule adenoma in females. NTP (1999) also noted increases in the incidence of testicular adenoma in male rats. Increased incidences of lung alveolar/bronchiolar adenoma or carcinoma were observed in male mice and liver hepatocellular adenoma or carcinoma in female mice, which provided some evidence of carcinogenic activity in male and female mice (NTP, 1999). IARC (2000) classified ethylbenzene as Group 2B, possibly carcinogenic to humans, based on the NTP studies.

3.6.5 Mixed Xylenes

Short-term inhalation of mixed xylenes (a mixture of three closely-related compounds) in humans may cause irritation of the nose and throat, nausea, vomiting, gastric irritation, mild transient eye irritation, and neurological effects.[62] Other reported effects include labored breathing, heart palpitation, impaired function of the lungs, and possible effects in the liver and kidneys.[63] Long-term inhalation exposure to xylenes in humans has been associated with a

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[58] Maltoni C, Conti B, Giuliano C and Belpoggi F, 1985. Experimental studies on benzene carcinogenicity at the Bologna Institute of Oncology: Current results and ongoing research. Am J Ind Med 7:415-446.

[59] Maltoni C, Ciliberti A, Pinto C, Soffritti M, Belpoggi F and Menarini L, 1997. Results of long-term experimental carcinogenicity studies of the effects of gasoline, correlated fuels, and major gasoline aromatics on rats. Annals NY Acad Sci 837:15-52.

[60] International Agency for Research on Cancer (IARC), 2000. Monographs on the Evaluation of Carcinogenic Risks to Humans. Some Industrial Chemicals. Vol. 77, p. 227-266. IARC, Lyon, France.

[61] National Toxicology Program (NTP), 1999. Toxicology and Carcinogenesis Studies of Ethylbenzene (CAS No. 100-41-4) in F344/N Rats and in B6C3F1 Mice (Inhalation Studies). Technical Report Series No. 466. NIH Publication No. 99-3956. U.S. Department of Health and Human Services, Public Health Service, National Institutes of Health. NTP, Research Triangle Park, NC.

[62] U.S. Environmental Protection Agency (U.S. EPA). 2003. Integrated Risk Information System File for Mixed Xylenes. Research and Development, National Center for Environmental Assessment, Washington, DC. This material is available electronically at <http://www.epa.gov/iris/subst/0270.htm>.

[63] Agency for Toxic Substances and Disease Registry (ATSDR), 2007. The Toxicological Profile for xylene is available electronically at <http://www.atsdr.cdc.gov/ToxProfiles/TP.asp?id=296&tid=53>.

number of effects in the nervous system including headaches, dizziness, fatigue, tremors, and impaired motor coordination.[64] EPA has classified mixed xylenes in Category D, not classifiable with respect to human carcinogenicity.

3.6.6 n-Hexane

The studies available in both humans and animals indicate that the nervous system is the primary target of toxicity upon exposure of n-hexane via inhalation. There are no data in humans and very limited information in animals about the potential effects of n-hexane via the oral route. Acute (short-term) inhalation exposure of humans to high levels of hexane causes mild central nervous system effects, including dizziness, giddiness, slight nausea, and headache. Chronic (long-term) exposure to hexane in air causes numbness in the extremities, muscular weakness, blurred vision, headache, and fatigue. Inhalation studies in rodents have reported behavioral effects, neurophysiological changes and neuropathological effects upon inhalation exposure to n-hexane. Under the Guidelines for Carcinogen Risk Assessment (U.S. EPA, 2005), the database for n-hexane is considered inadequate to assess human carcinogenic potential, therefore the EPA has classified hexane in Group D, not classifiable as to human carcinogenicity.[65]

3.6.7 Other Air Toxics

In addition to the compounds described above, other toxic compounds might be affected by this rule, including hydrogen sulfide (H_2S). Information regarding the health effects of those compounds can be found in EPA's IRIS database.[66]

3.7 References

Anenberg, S.C., *et al.* 2009. "Intercontinental impacts of ozone pollution on human mortality," *Environmental Science & Technology* 43:6482-6487.

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[65] U.S. EPA. 2005. Guidelines for Carcinogen Risk Assessment. EPA/630/P-03/001B. Risk Assessment Forum, Washington, DC. March. Available on the Internet at <http://www.epa.gov/ttn/atw/cancer_guidelines_final_3-25-05.pdf>.

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4 ECONOMIC IMPACT ANALYSIS AND DISTRIBUTIONAL ASSESSMENTS

4.1 Introduction

This section includes four sets of discussion for the proposed reconsideration: energy markets impacts, distributional impacts, small business impacts, and employment impacts.

4.2 Energy Markets Impacts

As it is implemented, the 2016 NSPS OOOOa may have impacts on energy production and markets which would be reduced under the proposed reconsideration. The 2016 NSPS RIA used the National Energy Modeling System (NEMS) to estimate the impacts to drilling activity, price, and quantity changes in the production of crude oil and natural gas, and changes in international trade of crude oil and natural gas national energy markets as a result of the 2016 NSPS OOOOa.[67] In that analysis, the EPA estimated the following impacts under the final 2016 NSPS OOOOa:

- Natural gas and crude oil drilling levels would decline slightly over the 2020 to 2025 period (by about 0.17 percent for natural gas wells and 0.02 percent for crude oil wells);
- Crude oil production would not change appreciably under the rule, while natural gas production would decline slightly over the 2020 to 2025 period (about 0.03 percent);
- Crude oil wellhead prices for onshore production in the lower 48 states were not estimated to change appreciably over the 2020 to 2025 period, while wellhead natural gas prices for onshore production in the lower 48 states were estimated to increase slightly over the 2020 to 2025 period (about 0.20 percent); and,
- Net imports of natural gas were estimated to increase slightly in 2020 (by about 0.12 percent) and in 2025 (by about 0.11 percent), while net imports of crude oil were not estimated to change appreciably over the 2020 to 2025 period.

As described earlier in this RIA, this proposed reconsideration includes proposing to reduce the stringency of the requirements on a substantial portion of the sources included in the 2016 NSPS OOOOa. The proposed option is expected to lead to total cost savings compared to the 2018 baseline. Relative to the baseline, the EAV of cost savings over the 2019-25 timeframe

[67] See Section 6.2 of the 2016 NSPS RIA

is about $41 million per year without including the forgone value of product recovery (about $4.5 million per year), or $36 million less per year when the forgone value of product recovery is included. As a result, the EPA expects that this deregulatory action, if finalized, would partially ameliorate the impacts estimated for the final NSPS in the 2016 NSPS RIA.

4.3 Distributional Impacts

The compliance cost savings and forgone benefits presented above are not expected to be felt uniformly across the population, and may not accrue to the same individuals or communities. OMB recommends including a description of distributional effects, as part of a regulatory analysis, "so that decision makers can properly consider them along with the effects on economic efficiency [i.e., net benefits]. Executive Order 12866 authorizes this approach." (U.S. Office of Management and Budget 2003). Understanding the distribution of the compliance cost savings and forgone benefits can aid in understanding community-level impacts associated with this action.[68] This section discusses the general expectations regarding how compliance cost savings and forgone health benefits might be distributed across the population, relying on a review of recent literature. EPA did not conduct a quantitative assessment of these distributional impacts for the proposed reconsideration, but the qualitative discussion in this section provides a general overview of the types of impacts that could result from this action.

4.3.1 Distributional Aspects of Compliance Cost Savings

The compliance costs associated with an environmental action can impact households by raising the prices of goods and services; the extent of the price increase depends on if and how producers pass-through those costs to consumers. The literature evaluates the distributional effects of introducing a new regulation; as the literature relates to the proposed reconsideration, which is deregulatory, these effects can be interpreted in reverse. Expenditures on energy are usually a larger share of low-income household income than that of other households, and this share falls as income increases. Therefore, policies that increase energy prices have been found

[68] Executive Order 12898, *Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations,* directs agencies to address impacts on minority and low-income populations, particularly those that may be considered disproportionate. EPA developed guidance, both in its *Guidelines for Preparing Economic Analyses* (U.S. EPA 2010) and *Technical Guidance for Assessing Environmental Justice in Regulatory Analyses* (U.S. EPA 2016) to provide recommendations for how to consider distributional impacts of rules on vulnerable populations.

to be regressive, placing a greater burden on lower income households (e.g., Burtraw et al., 2009; Hassett et al., 2009; Williams et al. 2015). However, compliance costs will not be solely passed on in the form of higher energy prices, but also through lower labor earnings and returns to capital in the sector. Changes in employment associated with lower labor earnings can have distributional consequences depending on a number of factors (Section 6.5 discusses employment effects further). Capital income tends to make up a greater proportion of overall income for high income households. As result, the costs passed through to households via lower returns to capital tend to be progressive, placing a greater share of the burden on higher income households in these instances (Rausch et al., 2011; Fullerton et al., 2011).

The ultimate distributional outcome will depend on how changes in energy prices and lower returns to labor and capital propagate through the economy and interact with existing government transfer programs. Some literature using an economy-wide framework finds that the overall distribution of compliance costs could be progressive for some policies due to the changes in capital payments and the expectation that existing government transfer indexed to inflation will offset the burden to lower income households[69] (Fullerton et al., 2011; Blonz et al., 2012). However, others have found the distribution of compliance costs to be regressive due to a dominating effect of changes in energy prices to consumers (Fullerton 2011; Burtraw, et. al., 2009; Williams, et al., 2015). There may also be significant heterogeneity in the costs borne by individuals within income deciles (Rausch et al., 2011; Cronin et al., 2017). Different classifications of households, such as on the basis of lifetime income rather than contemporaneous annual income, may provide notably different results (Fullerton and Metcalf, 2002; Fullerton et al., 2011). Furthermore, there may be important regional differences in the incidence of regulations. There are differences in the composition of goods consumed, regional production methods, the stringency of a rule, as well as the location of affected labor and capital ownership (the latter of which may be foreign-owned) (e.g. Caron et. al 2017; Hassett et al. 2009).

[69] The incidence of government transfer payments (e.g., Social Security) is generally progressive because these payments represent a significant source of income for lower income deciles and only a small source for high income deciles. Government transfer programs are often, implicitly or explicitly, indexed to inflation. For example, Social Security payments and veterans' benefits are adjusted every year to account for changes in prices (i.e., inflation).

4.3.2 Distributional Aspects of the Forgone Health Benefits

This section discusses the distribution of forgone health benefits that result from the proposed reconsideration. EPA guidance directs analysts to first consider the distribution of impacts in the baseline, prior to any regulatory action (see U.S. EPA 2016). Often the baseline incidence of health outcomes is greater among low-income or minority populations due to a variety of factors, including a greater number of pollution sources located where low-income and minority populations live, work and play (Bullard, et al. 2007; United Church of Christ 1987); greater susceptibility to a given exposure due to physiology or other triggers (Akinbami 2012); and pre-existing conditions (Schwartz et al 2011). EPA (2016) then recommends analysts examine the distribution of health outcomes under the policy scenarios being considered. Finally, this can be followed by an examination of the change between the baseline and policy scenario, taking note of whether the action ameliorates or exacerbates any pre-existing disparities.

Because the manner in which the health benefits of a rulemaking are distributed is based on the correlation of housing and work locations to changes in atmospheric concentrations of pollutants, it is difficult to fully know the distributional impacts of a rule. Air dispersion models provide some information on changes in pollution, but it may be difficult to identify the characteristics of populations in those affected areas, as well as to perform local air dispersion modeling nationwide. Furthermore, the overall distribution of health benefits will depend on whether and how any households change their housing location choice in response to air quality changes (Sieg et al., 2004).

4.4 Small Business Impacts

The Regulatory Flexibility Act (RFA; 5 U.S.C. §601 et seq.), as amended by the Small Business Regulatory Enforcement Fairness Act (Public Law No. 104121), provides that whenever an agency publishes a proposed rule, it must prepare and make available an initial regulatory flexibility analysis (IRFA), unless it certifies that the rule, if promulgated, will not have a significant economic impact on a substantial number of small entities (5 U.S.C. §605[b]). Small entities include small businesses, small organizations, and small governmental jurisdictions. An IRFA describes the economic impact of the rule on small entities and any

significant alternatives to the rule that would accomplish the objectives of the rule while minimizing significant economic impacts 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. As described in Section 2 of this RIA, this proposed reconsideration includes proposing to reduce the stringency of the requirements on a substantial portion of the sources included in the 2016 NSPS OOOOa. In addition, the three options being analyzed in this RIA would result in neutral or beneficial effects on the affected facilities, including small businesses. Where changes to the regulation are being proposed, they decrease burden to the industry through direct changes in the requirements (for example, reducing fugitive monitoring frequency at well sites, and excluding well sites without major production and processing equipment from fugitive emissions monitoring), increased clarity of requirements (for example, through more robust definitions), updating of the alternative means of limitation (for example specifying specific state level provisions as equivalent to the provisions being proposed in this reconsideration), and the streamlining of recordkeeping and reporting requirements. Relative to the baseline, the reduction in EAV of costs over the 2019-25 timeframe is about $41 million per year without including the forgone value of product recovery (about $4.5 million per year), or $36 million less per year when the forgone value of product recovery is included. As a result, the EPA expects that this deregulatory action, if finalized as proposed, would lessen the impacts estimated for the final NSPS in the 2016 NSPS RIA. We have therefore concluded that this action will relieve regulatory burden for all directly regulated small entities.

4.5 Employment Impacts

In this section, the EPA presents a qualitative discussion of the impacts of this rulemaking on employment.[70] E.O. 13777 directs federal agencies to consider a variety of issues regarding the characteristics and impacts of regulations, including the effect of regulations on jobs (Executive Order 13777). Employment impacts of environmental regulations are

[70] The employment analysis in this RIA is part of the EPA's ongoing effort to "conduct continuing evaluations of potential loss or shifts of employment which may result from the administration or enforcement of [the Act]" pursuant to CAA section 321(a).

composed of a mix of potential declines and gains in different areas of the economy over time. Regulatory employment impacts can vary across occupations, regions, and industries; by labor demand and supply elasticities; and in response to other labor market conditions. Isolating such impacts is a challenge, as they are difficult to disentangle from employment impacts caused by a wide variety of ongoing, concurrent economic changes.

Environmental regulation "typically affects the distribution of employment among industries rather than the general employment level" (Arrow *et. al.* 1996). Even if they are mitigated by long-run market adjustments to full employment, many regulatory actions have transitional effects in the short run (OMB 2015). These movements of workers in and out of jobs in response to environmental regulation are potentially important distributional impacts of interest to policy makers. Transitional job losses experienced by workers operating in declining industries, exhibiting low migration rates, or living in communities or regions where unemployment rates are high are of particular concern.

A discussion of partial employment impacts for affected entities in the oil and gas industry was completed in the 2016 NSPS RIA using detailed engineering information on labor requirements for each of the control strategies identified in the rule.[71] These bottom-up, engineering-based estimates represented only one portion of potential employment impacts within the regulated industry, and did not represent estimates of the *net* employment impacts of the rule. Labor changes may be required as part of an initial effort to comply with a regulation or required as a continuous or annual effort to maintain compliance. In the 2016 analysis, EPA estimated up-front and continual annual labor requirements by estimating hours of labor required and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). Overall, the 2016 NSPS OOOOa estimated the one-time labor requirement for the affected sector to be about 270 FTEs in 2020 and 2025, and the annual labor requirement was estimated to be about 1,100 FTEs in 2020 and 1,800 FTEs in 2025. Due to data and methodology limitations, other potential employment impacts in the affected industry and impacts in related industries were not estimated.

As the proposed reconsideration is likely to cause little change in oil and natural gas

[71] The EPA did not estimate the labor required to perform the professional engineer certification requirements in the 2016 NSPS OOOOa.

exploration and production, and many aspects of the 2016 NSPS OOOOa requirements are not affected by the proposed reconsideration, demand for labor employed in exploration and production and associated industries is unlikely to change greatly. For the affected oil and natural gas entities, some reductions in labor from 2016 NSPS OOOOa related requirements may be expected under the proposed reconsideration. For the proposed reconsideration, EPA expects there will be slight reductions in the labor required for compliance-related activities associated with the 2016 NSPS OOOOa requirements relating to fugitive emissions and inspections of closed vent systems. However, due to uncertainties associated with how the proposed reconsideration will influence the portfolio of activities associated with fugitive emissions-related requirements, EPA is unable to provide quantitative estimates of compliance-related labor changes. The EPA continues to explore the relevant theoretical and empirical literature and to seek public comments in order to ensure that the way the EPA characterizes the employment effects of its regulations is valid and informative.

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5 COMPARISON OF BENEFITS AND COSTS

5.1 Comparison of Benefits and Costs Across Regulatory Options

In this section, we present a comparison of the benefits and costs of this regulation. To be more consistent with traditional net benefits analysis, we modify the relevant terminology in the following tables, which present the costs, benefits and net benefits for this proposed action across regulatory options. We refer to the cost savings as presented in section 2 as the "benefits" of this proposed action and the forgone benefits as presented in section 3 as the "costs" of this proposed action. The net benefits are the benefits (cost savings) minus the costs (forgone benefits). As explained in the previous sections, all costs and benefits outlined in this RIA are estimated as the change from the updated baseline.

All benefits, costs, and net benefits shown in this section are presented as the PV of the costs and benefits of each option from 2019 through 2025 discounted back to 2016 under both a 7 percent and a 3 percent discount rate, and their associated EAV.

[REF _Ref511911959 \h] shows the estimated benefits, costs and net benefits for Option 1, the most stringent option. Option 1 is associated with a decrease in costs due to in-house certifications compared to all certifications being performed by a professional engineer. There are no forgone benefits associated with this action. Therefore, the net benefits stem entirely from the cost savings (or benefits as presented in the table). The net benefits from this option are the smallest compared to Options 2 and 3.

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Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Summary of the Present Value (PV) and Equivalent Annualized Value (EAV) of Forgone Monetized Benefits, Cost Savings, and Net Benefits for Option 1 from 2019 through 2025 (millions, 2016$)

	7%		3%	
	PV	**EAV**	**PV**	**EAV**
Benefits (Cost Savings)	$17	$2.9	$21	$3.3
Total Annual Cost Savings	*$17*	*$2.9*	*$21*	*$3.3*
Forgone Value of Product Recovery	*$0*	*$0*	*$0*	*$0*
Costs (Forgone Domestic Climate Benefits)[1]	$0	$0	$0	$0
Net Benefits[2]	$17	$2.9	$21	$3.3

[1] The forgone benefits estimates are calculated using estimates of the social cost of methane (SC-CH_4). SC-CH_4 values represent only a partial accounting of domestic climate impacts from methane emissions. This option is unlikely to affect emissions, therefore there are no monetized forgone benefits as a result of this option.
[2] Estimates may not sum due to independent rounding.

[REF _Ref511913510 \h] shows the estimated benefits, costs and net benefits for Option 2. Option 2 is the proposed option and results in net benefits greater than those of Option 1, but less than those of Option 3. In this option, we estimate the impact of in-house certifications, a step down in the fugitives monitoring frequency for all non-low production well sites to annual after two years, and an immediate reduction in monitoring frequency to annual for all low production well sites and all compressor stations on the Alaskan North Slope. The benefits (cost savings) are moderated by a decrease in the value of product recovery producers would have received under the 2016 NSPS OOOOa.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Summary of the Present Value (PV) and Equivalent Annualized Value (EAV) of Forgone Monetized Benefits, Cost

Savings, and Net Benefits for the Proposed Option 2 from 2019 through 2025 (millions, 2016$)

	7%		3%	
	PV	**EAV**	**PV**	**EAV**
Benefits (Total Cost Savings)	$209	$36	$265	$41
Total Annual Cost Savings	*$234*	*$41*	*$299*	*$47*
Forgone Value of Product Recovery	*$26*	*$4.5*	*$33*	*$5.2*
Costs (Forgone Domestic Climate Benefits)[1]	$7.2	$1.2	$28	$4.4
Net Benefits[2]	$201	$35	$237	$37

[1] The forgone benefits estimates are calculated using estimates of the social cost of methane (SC-CH_4). SC-CH_4 values represent only a partial accounting of domestic climate impacts from methane emissions. See Section 3.3 for more discussion.
[2] Estimates may not sum due to independent rounding.

[REF _Ref509483537 \h] shows the estimated benefits, costs and net benefits for Option 3. Option 3 is the least stringent option, and results in the greatest cost savings, forgone benefits, and net benefits. Under Option 3, fugitive emissions monitoring frequency is annual at non-low production well sites not on the Alaskan North Slope, biennial at all low production well sites not on the Alaskan North Slope, and all well sites on the Alaskan North slope are exempt. Compressor stations on the Alaskan North Slope are also exempt from fugitive emission monitoring, while all other compressor stations are required to perform quarterly monitoring.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Summary of the Present Value (PV) and Equivalent Annualized Value (EAV) of Forgone Monetized Benefits, Cost Savings, and Net Benefits for Option 3 from 2019 through 2025 (millions, 2016$)

	7%		3%	
	PV	**EAV**	**PV**	**EAV**
Benefits (Total Cost Savings)	$282	$49	$358	$56
Total Annual Cost Savings	*$317*	*$55*	*$404*	*$63*
Forgone Value of Product Recovery	*$36*	*$6.2*	*$45*	*$7.1*
Costs (Forgone Domestic Climate Benefits)[1]	$9.9	$1.7	$39	$6.1
Net Benefits[2]	$272	$47	$319	$50

[1] [1] The forgone benefits estimates are calculated using estimates of the social cost of methane (SC-CH_4). SC-CH_4 values represent only a partial accounting of domestic climate impacts from methane emissions. See Section 3.3 for more discussion.
[2] Estimates may not sum due to independent rounding.

[REF _Ref509483580 \h] provides a summary of the direct increase in emissions for each regulatory option. As explained in section 3, there are no changes in emissions estimated as a result of Option 1. Option 2 results in an increase in emissions compared to both option 1, and

the updated baseline. Option 3 results in the greatest increase in emissions compared to the baseline.

Table [STYLEREF 1 \s]-[SEQ Table * ARABIC \s 1] Summary of Total Emissions Increases across Options, 2019 through 2025

Pollutant	Option 1	Option 2 (Proposed)	Option 3
Methane (short tons)	0	200,000	280,000
VOC (short tons)	0	56,000	77,000
HAP (short tons)	0	2,100	2,900
Methane (metric tons)	0	180,000	250,000
Methane (million metric tons CO_2 Eq.)	0	4.5	6.2

5.2 Uncertainties and Limitations

Throughout the RIA, we considered a number of sources of uncertainty, both quantitatively and qualitatively, regarding emissions increases, forgone benefits, and cost savings of the proposed rule. We summarize the key elements of our discussions of uncertainty here:

- **Projection methods and assumptions:** As discussed in Section 2.4.2, over time, more facilities are newly established or modified in each year, and to the extent the facilities remain in operation in future years, the total number of facilities subject to the NSPS accumulates. The impacts of this rule are based on projections and growth rates consistent with the drilling activity in the 2018 Annual Energy Outlook. To the extent actual drilling activities diverge from the Annual Energy Outlook projections, the projected regulatory impacts estimated in this document will diverge. In addition, we assume one hundred percent compliance with the rule, starting from when the source becomes affected. If sources are not complying with the rule, at all or as written, the cost savings may be overestimated.
- **Years of analysis:** The years of analysis are 2019, to represent the first-year facilities are affected by this reconsideration, through 2025, to represent impacts of the rule over a longer period, as discussed in Section 2.4.2. While it is desirable to analyze impacts beyond 2025 in this RIA, the EPA has chosen not to do this largely because of the limited information available on the turnover rate of emissions sources and controls. Extending the analysis beyond 2025 would introduce substantial and increasing uncertainties in projected impacts of the proposed regulation.

- **State regulations in baseline:** In preparing the impacts analysis, the EPA reviewed state regulations and permitting requirements, as discussed in Section 2.4.2. Applicable facilities in these states with similar requirements to the proposed reconsideration are not included in the estimates of incrementally affected facilities presented in the RIA. This means that any additional costs and benefits incurred by facilities in these states to comply with the federal standards beyond the state requirements are not reflected in this RIA.
- **Wellhead natural gas prices used to estimate forgone revenues from natural gas recovery:** The compliance cost savings estimates presented in this RIA include the forgone revenue associated with the decrease in natural gas recovery resulting from the decrease in emissions reductions. As a result, the national compliance cost savings depends on the price of natural gas. Natural gas prices used in this analysis are from the projection of the Henry Hub price in the 2018 AEO. To the extent actual natural gas prices diverge from the AEO projections, the projected regulatory impacts estimated in this document will diverge.
- **Monetized forgone methane-related climate benefits:** The EPA considered the uncertainty associated with the social cost of methane (SC-CH_4) estimates, which were used to calculate the forgone domestic social benefits of the increase in methane emissions expected as a result of this reconsideration. Some uncertainties are captured within the analysis, while other areas of uncertainty have not yet been quantified in a way that can be modeled. Chapter 3 and the accompanying Appendix provides a detailed discussion of the ways in which the modeling underlying the development of the SC-CH_4 estimates used in this analysis addresses quantified sources of uncertainty, and presents a sensitivity analysis to show consideration of the uncertainty surrounding discount rates over long time horizons.
- **Non-monetized forgone benefits:** Numerous categories of forgone health, welfare, and climate benefits are not quantified and monetized in this RIA. These unquantified forgone benefits, including forgone benefits from increases in emissions of methane, VOCs and HAP, are described in detail in Chapter 3.

A. APPENDIX: UNCERTAINTY ASSOCIATED WITH ESTIMATING THE SOCIAL COST OF METHANE

A.1 Overview of Methodology Used to Develop Interim Domestic SC-CH_4 Estimates

The domestic SC-CH_4 estimates rely on the same ensemble of three integrated assessment models (IAMs) that were used to develop the IWG global SC-CH_4 (and SC-CO_2) estimates: DICE 2010, FUND 3.8, and PAGE 2009.[72] The three IAMs translate emissions into changes in atmospheric greenhouse concentrations, atmospheric concentrations into changes in temperature, and changes in temperature into economic damages. The emissions projections used in the models are based on specified socio-economic (GDP and population) pathways. These emissions are translated into atmospheric concentrations, and concentrations are translated into warming based on each model's simplified representation of the climate and a key parameter, equilibrium climate sensitivity. The effect of these Earth system changes is then translated into consumption-equivalent economic damages. As in the IWG exercise, these key inputs were harmonized across the three models: a probability distribution for equilibrium climate sensitivity; five scenarios for economic, population, and emissions growth; and discount rates.[73] All other model features were left unchanged. Future damages are discounted using constant discount rates of both 3 and 7 percent, as recommended by OMB Circular A-4.

The domestic share of the global SC-CH_4—i.e., an approximation of the climate change impacts that occur within U.S. borders[74]—is calculated directly in both FUND and PAGE. However, DICE 2010 generates only global estimates. Therefore, the EPA approximates U.S. damages as 10 percent of the global values from the DICE model runs, based on the results from a regionalized version of the model (RICE 2010) reported in Table 2 of Nordhaus (2017).[75] Although the regional shares reported in Nordhaus (2017) are specific to SC-CO_2, they still

[72] The full models names are as follows: Dynamic Integrated Climate and Economy (DICE); Climate Framework for Uncertainty, Negotiation, and Distribution (FUND); and Policy Analysis of the Greenhouse Gas Effect (PAGE).

[73] See the IWG's summary of its methodology in the docket, document ID number EPA-HQ-OAR-2015-0827-5886, "Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide (August 2016)". See also National Academies (2017) for a detailed discussion of each of these modeling assumptions.

[74] Note that inside the U.S. borders is not the same as accruing to U.S. citizens, which may be higher or lower.

[75] Nordhaus, William D. 2017. Revisiting the social cost of carbon. *Proceedings of the National Academy of Sciences of the United States,* 114(7): 1518-1523.

provide a reasonable interim approach for approximating the U.S. share of marginal damages from methane emissions. Direct transfer of the domestic share from the SC-CO_2 may understate the U.S. share of the IWG global SC-CH_4 estimates based on DICE due to the combination of three factors: a) regional damage estimates are known to be highly correlated with output shares (Nordhaus 2017, 2014), b) the U.S. share of global output decreases over time in all five EMF-22 based socioeconomic scenarios used for the model runs, and c) the bulk of the temperature anomaly (and hence, resulting damages) from a perturbation in emissions in a given year will be experienced earlier for CH_4 than CO_2 due to the shorter lifetime of CH_4 relative to CO_2.

The steps involved in estimating the social cost of CH_4 are similar to that of CO_2. The three integrated assessment models (FUND, DICE, and PAGE) are run using the harmonized equilibrium climate sensitivity distribution, five socioeconomic and emissions scenarios, constant discount rates described above. Because the climate sensitivity parameter is modeled probabilistically, and because PAGE and FUND incorporate uncertainty in other model parameters, the final output from each model run is a distribution over the SC-CH_4 in year t based on a Monte Carlo simulation of 10,000 runs. For each of the IAMs, the basic computational steps for calculating the social cost estimate in a particular year t are: 1.) calculate the temperature effects and (consumption-equivalent) damages in each year resulting from the baseline path of emissions; 2.) adjust the model to reflect an additional unit of emissions in year t; 3.) recalculate the temperature effects and damages expected in all years beyond t resulting from this adjusted path of emissions, as in step 1; and 4.) subtract the damages computed in step 1 from those in step 3 in each model period and discount the resulting path of marginal damages back to the year of emissions. In PAGE and FUND step 4 focuses on the damages attributed to the US region in the models. As noted above, DICE does not explicitly include a separate US region in the model and therefore, the EPA approximates U.S. damages in step 4 as 10 percent of the global values based on the results of Nordhaus (2017). This exercise produces 30 separate distributions of the SC-CH_4 for a given year, the product of 3 models, 2 discount rates, and 5 socioeconomic scenarios. Following the approach used by the IWG, the estimates are equally weighted across models and socioeconomic scenarios in order to consolidate the results into one distribution for each discount rate.

A.2 Treatment of Uncertainty in Interim Domestic SC-CH_4 Estimates

There are various sources of uncertainty in the SC-CH_4 estimates used in this analysis. Some uncertainties pertain to aspects of the natural world, such as quantifying the physical effects of greenhouse gas emissions on Earth systems. Other sources of uncertainty are associated with current and future human behavior and well-being, such as population and economic growth, GHG emissions, the translation of Earth system changes to economic damages, and the role of adaptation. It is important to note that even in the presence of uncertainty, scientific and economic analysis can provide valuable information to the public and decision makers, though the uncertainty should be acknowledged and when possible taken into account in the analysis (National Academies 2013).[76] OMB Circular A-4 also requires a thorough discussion of key sources of uncertainty in the calculation of benefits and costs, including more rigorous quantitative approaches for higher consequence rules. This section summarizes the sources of uncertainty considered in a quantitative manner in the domestic SC-CH_4 estimates.

The domestic SC-CH_4 estimates consider various sources of uncertainty through a combination of a multi-model ensemble, probabilistic analysis, and scenario analysis. We provide a summary of this analysis here; more detailed discussion of each model and the harmonized input assumptions can be found in the 2017 National Academies report. For example, the three IAMs used collectively span a wide range of Earth system and economic outcomes to help reflect the uncertainty in the literature and in the underlying dynamics being modeled. The use of an ensemble of three different models at least partially addresses the fact that no single model includes all of the quantified economic damages. It also helps to reflect structural uncertainty across the models, which stems from uncertainty about the underlying relationships among GHG emissions, Earth systems, and economic damages that are included in the models. Bearing in mind the different limitations of each model and lacking an objective basis upon which to differentially weight the models, the three integrated assessment models are given equal weight in the analysis.

Monte Carlo techniques were used to run the IAMs a large number of times. In each simulation the uncertain parameters are represented by random draws from their defined probability distributions. In all three models the equilibrium climate sensitivity is treated

[76] Institute of Medicine of the National Academies. 2013. Environmental Decisions in the Face of Uncertainty. The National Academies Press.

probabilistically based on the probability distribution from Roe and Baker (2007) calibrated to the IPCC AR4 consensus statement about this key parameter.[77] The equilibrium climate sensitivity is a key parameter in this analysis because it helps define the strength of the climate response to increasing GHG concentrations in the atmosphere. In addition, the FUND and PAGE models define many of their parameters with probability distributions instead of point estimates. For these two models, the model developers' default probability distributions are maintained for all parameters other than those superseded by the harmonized inputs (i.e., equilibrium climate sensitivity, socioeconomic and emissions scenarios, and discount rates). More information on the uncertain parameters in PAGE and FUND is available upon request.

For the socioeconomic and emissions scenarios, uncertainty is included in the analysis by considering a range of scenarios selected from the Stanford Energy Modeling Forum exercise, EMF-22. Given the dearth of information on the likelihood of a full range of future socioeconomic pathways at the time the original modeling was conducted, and without a basis for assigning differential weights to scenarios, the range of uncertainty was reflected by simply weighting each of the five scenarios equally for the consolidated estimates. To better understand how the results vary across scenarios, results of each model run are available in the docket.

The outcome of accounting for various sources of uncertainty using the approaches described above is a frequency distribution of the SC-CH_4 estimates for emissions occurring in a given year for each discount rate. Unlike the approach taken for consolidating results across models and socioeconomic and emissions scenarios, the SC-CH_4 estimates are not pooled across different discount rates because the range of discount rates reflects both uncertainty and, at least in part, different policy or value judgements; uncertainty regarding this key assumption is discussed in more detail below. The frequency distributions reflect the uncertainty around the input parameters for which probability distributions were defined, as well as from the multi-model ensemble and socioeconomic and emissions scenarios where probabilities were implied by the equal weighting assumption. It is important to note that the set of SC-CH_4 estimates obtained from this analysis does not yield a probability distribution that fully characterizes

[77] Specifically, the Roe and Baker distribution for the climate sensitivity parameter was bounded between 0 and 10 with a median of 3 °C and a cumulative probability between 2 and 4.5 °C of two-thirds.

uncertainty about the SC-CH_4 due to impact categories omitted from the models and sources of uncertainty that have not been fully characterized due to data limitations.

Figure 1 presents the frequency distribution of the domestic SC-CH_4 estimates for emissions in 2020 for each discount rate. Each distribution represents 150,000 estimates based on 10,000 simulations for each combination of the three models and five socioeconomic and emissions scenarios.[78] In general, the distributions are skewed to the right and have long right tails, which tend to be longer for lower discount rates. To highlight the difference between the impact of the discount rate on the SC-CH_4 and other quantified sources of uncertainty, the bars below the frequency distributions provide a symmetric representation of quantified variability in the SC-CH_4 estimates conditioned on each discount rate. The full set of SC-CH_4 results through 2050 is available as part of the RIA analysis materials.

[78] Although the distributions in Figure 1 are based on the full set of model results (150,000 estimates for each discount rate), for display purposes the horizontal axis is truncated with 0.001 to 0.013 percent of the estimates lying below the lowest bin displayed and 0.471 to 3.356 percent of the estimates lying above the highest bin displayed, depending on the discount rate.

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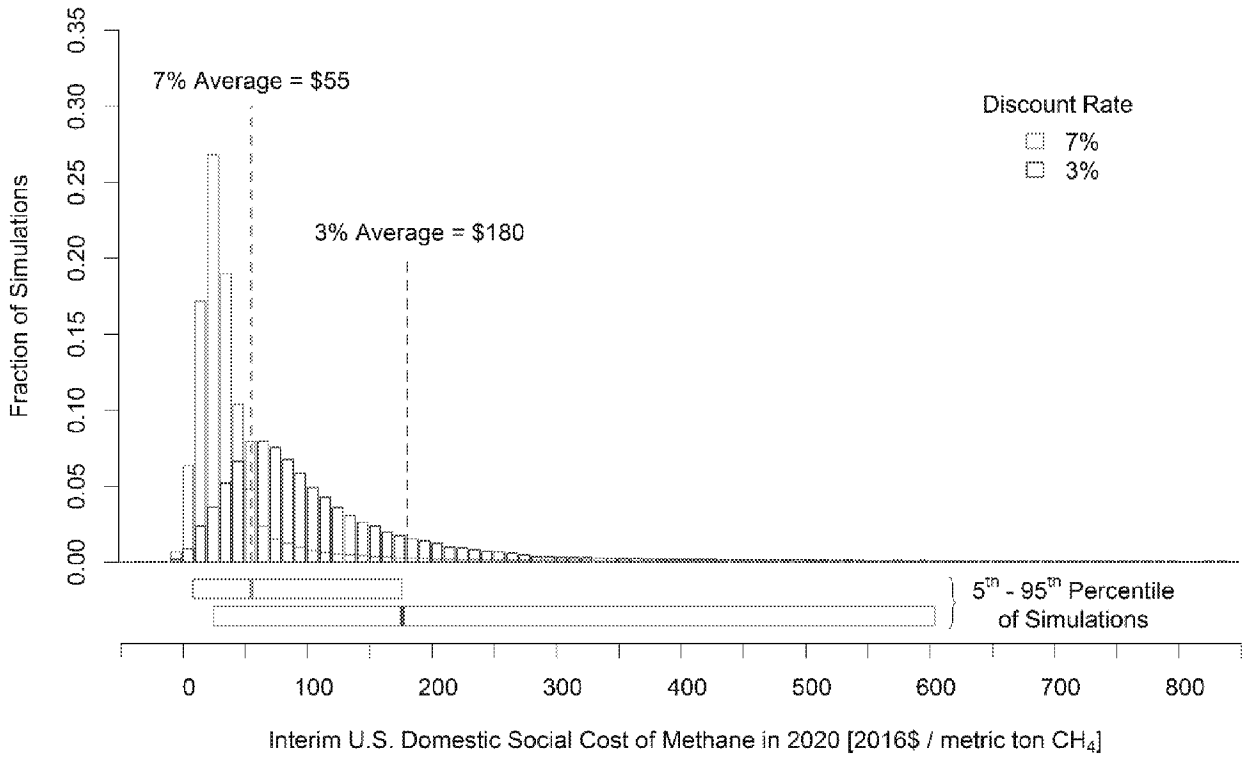

Figure 1. Frequency Distribution of Interim Domestic SC-CH_4 Estimates for 2020 (in 2016$ per metric ton CH_4)

As illustrated by the frequency distributions in Figure 1, the assumed discount rate plays a critical role in the ultimate estimate of the social cost of methane. This is because CH_4 emissions today continue to impact society far out into the future,[79] so with a higher discount rate, costs that accrue to future generations are weighted less, resulting in a lower estimate. Circular A-4 recommends that costs and benefits be discounted using the rates of 3 percent and 7 percent to reflect the opportunity cost of consumption and capital, respectively. Circular A-4 also recommends quantitative sensitivity analysis of key assumptions[80], and offers guidance on what sensitivity analysis can be conducted in cases where a rule will have important intergenerational benefits or costs. To account for ethical considerations of future generations and potential

[79] Although the atmospheric lifetime of CH_4 is notably shorter than that of CO_2, the impacts of changes in contemporary CH_4 emissions are also expected to occur over long time horizons that cover multiple generations. For more discussion, see document ID number EPA-HQ-OAR-2015-0827-5886, "Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social Cost of Methane and the Social Cost of Nitrous Oxide (August 2016)".

[80] "If benefit or cost estimates depend heavily on certain assumptions, you should make those assumptions explicit and carry out sensitivity analyses using plausible alternative assumptions." (OMB 2003, page 42).

uncertainty in the discount rate over long time horizons, Circular A-4 suggests "further sensitivity analysis using a lower but positive discount rate in addition to calculating net benefit using discount rates of 3 and 7 percent" (page 36) and notes that research from the 1990s suggests intergenerational rates "from 1 to 3 percent per annum" (OMB 2003). We consider the uncertainty in this key assumption by calculating the domestic SC-CH_4 based on a 2.5 percent discount rate, in addition to the 3 and 7 percent used in the main analysis. Using a 2.5 percent discount rate, the average domestic SC-CH_4 estimate across all the model runs for emissions occurring in 2019 is $220 per metric ton of CH_4 (2016$)[81]; in this case the forgone domestic climate benefits of the proposed option are $3.1 million in 2019 under a 2.5 percent discount rate. By 2025, the average domestic SC-CH_4 using a 2.5 percent discount rate is $250 per metric ton of CH_4 (2016$), and the corresponding forgone domestic climate benefits of the proposed action increase to $7.6 million. The PV of the forgone domestic climate benefits under a 2.5 percent discount rate is $37 million, with a corresponding EAV of $5.7 million per year.

In addition to the approach to accounting for the quantifiable uncertainty described above, the scientific and economics literature has further explored known sources of uncertainty related to estimates of the social cost of carbon and other greenhouse gases. For example, researchers have examined the sensitivity of IAMs and the resulting estimates to different assumptions embedded in the models (see, e.g., Hope 2013, Anthoff and Tol 2013, Nordhaus 2014, and Waldhoff et al. 2011, 2014). However, there remain additional sources of uncertainty that have not been fully characterized and explored due to remaining data limitations. Additional research is needed to expand the quantification of various sources of uncertainty in estimates of the social cost of carbon and other greenhouse gases (e.g., developing explicit probability distributions for more inputs pertaining to climate impacts and their valuation). On the issue of intergenerational discounting, some experts have argued that a declining discount rate would be appropriate to analyze impacts that occur far into the future (Arrow et al., 2013). However, additional research and analysis is still needed to develop a methodology for implementing a declining discount rate and to understand the implications of applying these theoretical lessons in practice. The 2017 National Academies report also provides recommendations pertaining to discounting, emphasizing the need to more explicitly model the uncertainty surrounding discount

[81] The estimates are adjusted for inflation using the GDP implicit price deflator and then rounded to two significant digits.

rates over long time horizons, its connection to uncertainty in economic growth, and, in turn, to climate damages using a Ramsey-like formula (National Academies 2017). These and other research needs are discussed in detail in the 2017 National Academies' recommendations for a comprehensive update to the current methodology, including a more robust incorporation of uncertainty.

A.3 Forgone Global Climate Benefits

In addition to requiring reporting of impacts at a domestic level, OMB Circular A-4 states that when an agency "evaluate[s] a regulation that is likely to have effects beyond the borders of the United States, these effects should be reported separately" (page 15).[82] This guidance is relevant to the valuation of damages from GHGs, given that most GHGs (including CH_4) contribute to damages around the world independent of the country in which they are emitted. Therefore, in this section we present the forgone global climate benefits from this rulemaking using the global SC-CH_4 estimates – i.e., reflecting quantified impacts occurring in both the U.S. and other countries—corresponding to the model runs that generated the domestic SC-CH_4 estimates used in the main analysis. The average global SC-CH_4 estimate across all the model runs for emissions occurring over the years analyzed in this RIA (2019-2025) range from $350 to $450 per metric ton of CH_4 emissions (in 2016 dollars) using a 7 percent discount rate, and $1,300 to $1,600 per metric ton of CH_4 using a 3 percent discount rate.[83] The domestic SC-CH_4 estimates presented above are approximately 15 percent and 13 percent of these global SC-CH_4 estimates for the 7 percent and 3 percent discount rates, respectively. Applying these estimates to the forgone CH_4 emission reductions results in estimated forgone global climate benefits ranging from $4.4 million in 2019 to $9.1 million in 2025, using a 7 percent discount rate. The PV of the

[82] While Circular A-4 does not elaborate on this guidance, the basic argument for adopting a domestic only perspective for the central benefit-cost analysis of domestic policies is based on the fact that the authority to regulate only extends to a nation's own residents who have consented to adhere to the same set of rules and values for collective decision-making, as well as the assumption that most domestic policies will have negligible effects on the welfare of other countries' residents (EPA 2010; Kopp et al. 1997; Whittington et al. 1986). In the context of policies that are expected to result in substantial effects outside of U.S. borders, an active literature has emerged discussing how to appropriately treat these impacts for purposes of domestic policymaking (e.g., Gayer and Viscusi 2016, 2017; Anthoff and Tol, 2010; Fraas et al. 2016; Revesz et al. 2017). This discourse has been primarily focused on the regulation of greenhouse gases (GHGs), for which domestic policies may result in impacts outside of U.S. borders due to the global nature of the pollutants.

[83] The estimates are adjusted for inflation using the GDP implicit price deflator and then rounded to two significant digits.

forgone global climate benefits using a 7 percent discount rate is $47 million, with an associated EAV of $8.2 million per year. The estimated forgone global climate benefits are $19 million in 2019 and increase to $46 million in 2025 using a 3 percent rate. The PV of the forgone global climate benefits using a 3 percent discount rate is $224 million, with an associated EAV of $35 million per year. Under the sensitivity analysis considered above using a 2.5 percent discount rate, the average global SC-CH_4 estimate across all the model runs for emissions occurring in 2019-2025 ranges from $1,800 to $2,100 per metric ton of CH_4 (2016$). The forgone global climate benefits are estimated to be $25 million in 2019 and $62 million in 2025 using a 2.5 percent discount rate. The PV of the forgone global climate benefits using a 2.5 percent discount rate is $302 million, with an associated EAV of $46 million per year. All estimates are reported in 2016 dollars.

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MEMORANDUM

TO: EPA Docket ID No. EPA-HQ-OAR-2017-0483

DATE: April 12, 2018

SUBJECT: Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa

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1.0 INTRODUCTION

This memorandum summarizes the requirements of various state fugitive emissions programs for well sites and compressor stations. It compares each state programs' requirements to the proposed revisions to the Oil and Natural Gas Sector New Source Performance Standards (NSPS) at 40 CFR Part 60, Subpart OOOOa.

2.0 BACKGROUND

On June 3, 2016, the EPA published a final rule titled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources" in the **Federal Register** ("2016 NSPS OOOOa"). This rule introduced fugitive emissions requirements for the collection of fugitive emissions components located at well sites and compressor stations. The EPA has granted reconsideration of several issues in the 2016 NSPS OOOOa, including the fugitive emissions requirements and the process and criteria for requesting and receiving approval for the use of an alternative means of emission limitation (AMEL). To support the proposed reconsideration of the 2016 NSPS OOOOa ("2018 Proposal"), EPA evaluated the equivalence of existing state programs to the fugitive emissions requirements in the 2018 Proposal.

This memorandum details the process taken to evaluate equivalency of these existing programs and provides support for the proposed alternative fugitive standards contained in the 2018 Proposal. Section 3.0 provides a summary of the 2016 NSPS OOOOa and the proposed requirements in the 2018 Proposal. In section 4.0, we describe the methodology and criteria used for evaluating equivalency. Section 5.0 provides an evaluation of the existing programs that were included in this analysis. A summary of the conclusions of this analysis is included in section 6.0. Links to each of the programs evaluated in this analysis are provided in Appendix 1.

3.0 FUGITIVE EMISSIONS REQUIREMENTS IN 2016 NSPS OOOOa AND 2018 PROPOSAL

The 2016 NSPS OOOOa sets standards to control greenhouse gases (GHG) (in the form of limitations on methane) and volatile organic compound (VOC) emissions from fugitive emissions components at well sites and compressor stations. Specifically, owners and operators must conduct semiannual monitoring for fugitive emissions at well sites and quarterly monitoring for fugitive emissions at compressor stations. Additionally, well sites located on the Alaskan North Slope must conduct annual monitoring. This monitoring must be conducted using optical gas imaging (OGI), and repairs are required for any visible emissions observed. Method

21 of Appendix A-7 to Part 60 ("Method 21") may be used as an alternative monitoring method at a repair threshold level of 500 parts per million (ppm). Repairs must be made within 30 days of finding fugitive emissions, and a resurvey of the repaired component is required within 30 days of the repair using either OGI or Method 21. When using OGI for this resurvey, no visible emissions indicates successful repair. For Method 21, an instrument reading below 500 ppm indicates successful repair, or the presence of no visible emissions if using a soap solution. A monitoring plan that covers the collection of fugitive emissions components at a well site or compressor station within a company-defined area must be developed and implemented.

The 2018 Proposal includes amendments to these fugitive emissions standards. For instance, we are proposing to revise the monitoring frequency for well sites to semiannual for a 2-year period, followed by annual monitoring for well sites that are not considered low production well sites. For low production well sites, we are proposing annual monitoring. Low production well sites are well sites where the average combined oil and natural gas production is less than 15 barrels of oil equivalent (boe) per day, averaged over the first 30 days of production. The 2018 Proposal does not propose any changes to the quarterly monitoring for compressor stations. Additionally, we are proposing separate monitoring requirements for compressor stations located on the Alaskan North Slope (annual monitoring). The 2018 Proposal includes changes to the repair deadlines for fugitive emissions; specifically, a first attempt at repair is required within 30 days of finding fugitive emissions, with a final repair that includes the resurvey within 60 days of finding the fugitive emissions.

A summary of the fugitive emissions requirements within the 2016 NSPS OOOOa and the 2018 Proposal is provided in Table 1.

Table 1. Summary of Fugitive Emissions Requirements in 2016 NSPS OOOOa and 2018 Proposal

Regulation	40 CFR Part 60, Subpart OOOOa			
	2016 NSPS OOOOa		2018 Proposal	
Monitoring Instrument	OGI	Method 21	OGI	Method 21
Leak Definition	Visible leak	500 ppm	Visible leak	500 ppm
Initial Monitoring				
- *Well Sites*	60 days		60 days	
- *Compressor Stations*				
Monitoring Frequency				
- *Well Sites*	Semiannual		Semiannual for two years and annual thereafter	
- *Low Production Wells*			Annual	
- *Compressor Stations*	Quarterly		Quarterly	
Repair				
- *First Attempt*	NA		30 days	
- *Final Repair*	30 days		60 days	
- *Resurvey*	30 days from repair		Included in final repair	
- *DOR Deadline*	Next scheduled shutdown, or 2 years		Next scheduled shutdown, or 2 years	

4.0 SUMMARY OF METHODOLOGY USED TO EVALUTATE EQUIVALENCY

This memorandum provides our evaluation of the fugitive emissions requirements for states with an existing fugitive emissions program. For this evaluation, we analyzed the components that were included in the fugitive emissions programs, the affected facilities, the effective date(s) of the program, approved monitoring instruments, fugitive emissions definitions, monitoring frequencies, repair and resurvey timelines, and delay of repair (DOR) provisions. Equivalency determinations were made by comparing each of these aspects to those of the 2018 Proposal and by considering the requirements in the broader context of their fugitive emissions programs. The states that we analyzed were selected based on programs that we reviewed in previous actions and through a review of regulations and permit information for other states with known oil and gas activities.

This analysis was limited to information from state programs that were publicly available at the time of production of this memorandum and may not include state programs that are currently being drafted or proposed. For this memorandum, we reviewed fugitive emission programs from Alaska, California, Colorado, Montana, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, Utah, West Virginia, and Wyoming. States that are not included in this analysis either do not have requirements, or we were unable to locate requirements for this analysis. A summary of each of the programs is provided in the following section.

5.0 ANALYSIS OF STATE FUGITIVE EMISSIONS REQUIREMENTS

5.1 Components

As mentioned in the previous section, this analysis began by examining the specific fugitive emissions components subject to the requirements in each state program. Only one state program (Wyoming) was identified that explicitly includes all the components that are included in the 2018 Proposal, although there are certain key components that are included in most of the state programs (connectors, flanges, pressure relief devices (PRDs), and valves). A comparison of the types of components included in the state programs and the 2018 Proposal is presented in Table 2.

5.2 Alaska

Title 18, Chapter 50 of the Alaska Administrative Code (AAC) adopts the 2012 NSPS OOOO requirements for Title V sources.[1] While this does not require fugitive emissions programs for well sites or compressor stations, in 2009, the state's Sub-Cabinet on Climate Change, within the Office of the Governor, recommended assessing the potential emissions reductions and costs associated with a fugitive emissions program.[2] We were unable to locate any additional information on this effort. Therefore, we are not able to evaluate equivalency of these requirements to the 2018 Proposal.

5.3 California

The California Air Resources Board (CARB) finalized fugitive emissions requirements for well sites and compressors stations on July 17, 2017, with an effective date of January 1, 2018.[3] A summary of California's fugitive emissions requirements is provided in Table 3.

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[1] 18 AAC 50.040(a)(2)(WW); available at http://www.legis.state.ak.us/basis/aac.asp#18.50.040.

[2] Alaska Climate Change Strategy's Mitigation Advisory Group Final Report: Greenhouse Gas Inventory and Forecast and Policy Recommendations Addressing Greenhouse Gas Reduction in Alaska (2009); available at http://climatechange.alaska.gov/mit/mag.htm

[3] California regulations available at https://govt.westlaw.com/calregs/Browse/Home/California/CaliforniaCodeofRegulations?guid=I401BB8146DA14B519A991D7827913AEE&originationContext=documenttoc&transitionType=Default&contextData=(sc.Default).

Table 2. Components Included in the 2018 Proposal and State Requirements

	2018 Proposal	California	Colorado	Montana[4]	North Dakota[5]	Ohio	Pennsylvania[6]	Texas[7]	Utah	Wyoming
Compressors	X				X	X	X	X	X	X
Connectors	X	X[8]	X		X	X	X	X	X	X
Covers	X				X	X	X		X	X
CVSs	X[9]				X	X	X		X	X
Flanges	X	X	X		X	X	X	X	X	X
Instruments	X				X		X		X	X
Meters	X[10]	X			X		X		X	X
OELs	X	X			X	X	X	X	X	X
PRDs	X	X	X		X	X	X	X	X	X
Storage Vessels	X[11]				X	X	X			X
Thief Hatches	X				X		X	X	X	X
Valves	X	X	X		X	X	X	X	X	X
(Other)	X	X	X	X	X	X	X	X	X	X

[4] Montana only requires inspection of "VOC piping components".
[5] The North Dakota consent decree does not provide a definition for components. For the analysis, EPA assumes all the 2018 Proposal components are included.
[6] Pennsylvania permit language does not list component types to be inspected. For this analysis, EPA assumes all of the 2018 Proposal components are included. Exemption No. 38 only includes connectors, covers, flanges, storage vessels, valves, and other components.
[7] Texas does not include definitions for "components" but mentions certain components in their requirements.
[8] "Threaded connection".
[9] Only includes those not subject to 40 CFR §§60.5397a or 60.5411a.
[10] Does not include meters owned by third-parties.
[11] Only includes those not subject to 40 CFR §60.5395a.

Table 3. Summary of Fugitive Emissions Requirements in California

Regulation	Cal. Code Regs. tit. 17, § 95665-95677	
Effective Date	January 1, 2018	January 1, 2020
Monitoring Instrument	Method 21	
Leak Definition	10,000 ppm	1,000 ppm
Initial Monitoring		
- *Well Sites*	90 days	
- *Compressor Stations*		
Monitoring Frequency		
- *Well Sites*	Quarterly	
- *Low Production Wells*		
- *Compressor Stations*		
Repair		
- *First Attempt*	NA	
- *Final Repair*	(See Table 4)	
- *Resurvey*	Within repair timeframe	
- *DOR Deadline*	Next process shutdown or 12 months, whichever is sooner	
- *Additional DOR Info*	If parts needed, repair within 30 days of required date; DOR if deemed critical to reliability of public gas system	

The regulated components include threaded connections, flanges, meters, OELs, PRDs, valves, fittings, process drains, stuffing boxes, pipes, seal fluid systems, diaphragms, hatches, sight-glasses, well casings, pneumatic devices, and reciprocating compressor rod packing and seals. Weekly audio-visual and quarterly Method 21 inspections are required. OGI may be used as a screening tool prior to using Method 21 for quarterly inspections. The repair requirements change for leaks that are detected on or after January 1, 2020 because of the phase-in period of the rule that extends from January 1, 2018 to December 31, 2019. The timeline for repair also depends on the ppm instrument reading observed during Method 21 monitoring, as presented in Table 4:

Table 4. California Timelines to Finish Leak Repair After Detection (Days)

	1,000-9,999 ppm	**10,000-49,999 ppm**	**50,000 ppm or greater**
Before 2020	(N/A)	14	5
2020 and After	14	5	2

Critical components[12] or critical process units[13] must be repaired during the next scheduled shutdown or within 12 months of detecting the leak, whichever is sooner. The regulations also include DOR provision for when parts are needed and for when a component is considered to be critical to the reliability of the public gas system. Components used exclusively for crude oil with an American Petroleum Institute (API) gravity less than 20 are exempt from the fugitive emissions requirements. Records of when the inspection took place, components found leaking, repair dates, and leak concentrations before and after repair are required. Annual reporting of the results of all weekly and quarterly inspections, including the initial and final concentrations of each component, are also required. The annual reporting form is included in Appendix 1.

Table 5 provides a summary of the criteria evaluated for equivalency and our equivalency determination of California's fugitive emissions requirements to the 2018 Proposal:

Table 5. Equivalency of California's Fugitive Emissions Requirements to 2018 Proposal

Regulation	Cal. Code Regs. tit. 17, § 95665-95677	
Effective Date	January 1, 2018	January 1, 2020
Monitoring Instrument	Method 21	
Leak Definition	No	1,000 ppm – Yes
Initial Monitoring		
- *Well Sites*	No	
- *Compressor Stations*		
Monitoring Frequency		
- *Well Sites*	Yes	
- *Low Production Wells*		
- *Compressor Stations*		
Repair		
- *Final Repair*	Yes	
- *Resurvey*	Yes	
- *DOR Deadline*	Yes	

5.4 Colorado

Fugitive emissions requirements for oil and gas facilities in Colorado are located in the state's Regulation 7.[14] There are two sets of fugitive emissions requirements: one for facilities in

[12] A component that would require the shutdown of a critical process unit if that component was shutdown/disabled
[13] A process unit or group of components that must remain in service because of its importance to the overall process that requires it to continue to operate, and has no equivalent equipment to replace it or cannot be bypassed, and it is technically infeasible to repair leaks from that process unit without shutting it down and opening the process unit to the atmosphere
[14] Colorado regulations available at https://www.sos.state.co.us/CCR/DisplayRule.do?action=ruleinfo&ruleId=2341&deptID=16&agencyID=7&deptNa

ozone nonattainment areas (section XII.L) and one that covers the entire state (section XVII.F). A summary of these two sets of requirements is presented in Table 6.

Table 6. Summary of Fugitive Emissions Requirements in Colorado

Regulation	Regulation 7, Section XII.L			Regulation 7, Section XVII.F		
Effective Date	June 30, 2018			October 15, 2014 (well sites); January 1, 2015 (compressor stations)		
Monitoring Instrument	OGI	Method 21	Other approved	OGI	Method 21	Other approved
Leak Definition	Visible leak	500 ppm	State-defined	Visible leak	500 ppm	Visible leak
Initial Monitoring						
- *Well Sites*	15-30 days			(See Table 8)		
- *Compressor Stations*	90 days			(See Table 9)		
Monitoring Frequency						
- *Well Sites*	Based on Volatile Organic Compound (VOC) emissions: tpy ≥ 1 and ≤ 6 – Annual; tpy > 6 – Semiannual			(See Table 7)		
- *Low Production Wells*						
- *Compressor Stations*	Quarterly					
Repair						
- *First Attempt*	5 working days			5 working days		
- *Final Repair*	30 working days			NA		
- *Resurvey*	15 days of repair			15 days of repair		
- *DOR Deadline*	Next scheduled shutdown, with final repair within 2 years			Next scheduled shutdown		
- *Additional DOR Info*	If parts are ordered, repair within 15 days of receipt; if other good cause, repair within 15 days after cause ceases to exist			If parts are ordered, repair within 15 days of receipt; if other good cause, repair within 15 days after cause ceases to exist		

Both programs regulate the following types of components: connectors, flanges, PRDs, vales, pump seals, and other openings on a controlled storage tank. Components in process streams consisting of glycol, amine, produced water, or methanol are not included in the programs. Instrument monitoring for leaks is required using Method 21, OGI, or a state approved instrument monitoring method (AIMM). Leaks are defined as a measured hydrocarbon concentration greater than 500 ppm when Method 21 is used, and as detectable emissions when

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OGI or AIMM are used. Operators must make their first attempt to repair leaks within 5 days after detection, and components must be resurveyed within 15 days of repair in order to ensure that the components are no longer leaking. DOR provisions are also included for situations where a shutdown is required or if parts are unavailable. If the operator needs to order parts, the repair must be made within 15 days of receipt of those parts.

For facilities in ozone nonattainment areas, the effective date of the fugitive emissions requirements is June 30, 2018. Well sites must conduct initial monitoring within 15 to 30 days after startup, and compressor stations must conduct initial monitoring within 90 days after startup. For well sites, the monitoring frequency is dependent on the uncontrolled VOC emissions from the highest emitting storage tank at the well site. If no storage tanks are present, then the monitoring frequency is based on the controlled VOC emissions from the well site. If the emissions are 1 ton per year (tpy) or greater but less than 6 tpy, then annual instrument monitoring is required. If the emissions are 6 tpy or greater, then semiannual monitoring is required. For compressor stations, quarterly instrument monitoring is required, regardless of emissions. Operators are required to complete leak repairs within 30 days after detection for these areas. If a shutdown is required to make repairs, then repairs must be completed during the next scheduled shutdown, or within two years.

For the statewide fugitive emissions requirements, the effective dates are October 15, 2014, and January 1, 2015, for well sites and compressor stations, respectively. Similar to the ozone nonattainment area requirements, the instrument monitoring frequency for a well site is dependent on the VOC emissions and the equipment present at the well site. For compressor stations, the frequency is based on the fugitive VOC emissions from the compressor station. The different frequency requirements for each type of facility are presented in Table 7.

Table 7. Colorado State-Wide Instrument Monitoring Frequencies

	Frequency
Well sites without storage tanks: Controlled VOC emissions (tpy)	
- > 0 and ≤ 6	One-time
- > 6 and ≤ 12	Annually
- > 12 and ≤ 20	Quarterly
- > 20	Monthly
Well sites with storage tanks: Uncontrolled VOC emissions from highest emitting tank (tpy)	
- > 0 and ≤ 6	One-time
- > 6 and ≤ 12	Annually
- > 12 and ≤ 50	Quarterly
- > 50	Monthly
Compressor stations: Fugitive VOC emissions (tpy)	
- > 0 and ≤ 12	Annually
- > 12 and ≤ 50	Quarterly
- > 50	Monthly

Initial monitoring requirements for compressor stations and well sites are presented in Tables 8 and 9, respectively.

Table 8. Colorado State-Wide Compressor Station Initial Monitoring

	Fugitive VOC Emissions	
Construction Date	tpy > 0 and ≤ 50	tpy > 50
On or Before January 1, 2015	90	30
After January 1, 2015	(Upon startup)	

Table 9. Colorado State-Wide Well Site Initial Monitoring

	Instrument Monitoring Frequency		
Construction Date	One-Time	Monthly	Other
On or After October 15, 2014	15-30 days after startup		
Before October 15, 2014	By January 1, 2016	30 days	90 days

According to the statement of basis and purpose within Regulation 7, distinctions between well sites with storage tanks and those without were used to complement the state's Storage Tank Emissions Monitoring programs. A 2014 guidance memo also clarifies that tank

batteries are included in the Regulation 7 definition for a "well production facility". [15] Monthly audio-visual-olfactory (AVO) inspections are also required for well sites that do not conduct monthly instrument monitoring. If a shutdown is required to repair any instrument monitoring leak identified, the leak must be repaired during the next scheduled shutdown. The recordkeeping form is included in Appendix 1.

Table 10 provides a summary of the criteria evaluated for equivalency and our determination of equivalency of Colorado's fugitive emissions requirements to the 2018 Proposal.

Table 10. Equivalency of Colorado's Fugitive Emissions Requirements to 2018 Proposal

Regulation	Regulation 7, Section XII.L		Regulation 7, Section XVII.F	
Effective Date	June 30, 2018		October 15, 2014 (well sites); January 1, 2015 (compressor stations)	
Monitoring Instrument	OGI	Method 21	OGI	Method 21
Leak Definition	Yes	Yes	Yes	Yes
Initial Monitoring				
- *Well Sites*	Yes		Yes[16]	
- *Compressor Stations*	No		Yes (> 50 tpy VOC emissions or constructed after January 1, 2015)	
Monitoring Frequency				
- *Well Sites*	Yes[17]		Yes[18]	
- *Low Production Wells*	Yes (> 1 tpy uncontrolled VOC emissions)		Yes[19]	
- *Compressor Stations*	Yes		Yes (> 12 tpy fugitive VOC emissions)	
Repair				
- *First Attempt*	Yes		Yes	
- *Final Repair*			No	
- *Resurvey*			Yes	
- *DOR Deadline*			No	

[15] Laplante, C. and S. Rucker (2014). Guidance for Oil & Gas Industry Regulation 7, Section XVII.F, Leak Detection and Repair Program for Well Production Facilities and Natural Gas Compressor Stations and Section XVII.B, General Provisions for Open Ended Valves or Lines. Denver, CO, CDPHE Stationary Sources Program. Available at https://www.colorado.gov/pacific/cdphe/summary-oil-and-gas-emissions-requirements

[16] If well site was constructed before October 15, 2014, and does not have one-time or monthly monitoring, Colorado requirements are not considered equivalent

[17] For sites with > 6 tpy uncontrolled VOC emissions for the first two years and > 1 tpy thereafter

[18] First two years – sites w/ tanks: > 12 tpy VOC emissions from highest emitting tank, sites w/out tanks: > 12 tpy controlled VOC emissions; then sites w/ tanks: > 6 tpy VOC emissions from highest emitting tank; for sites w/out tanks: > 6 tpy controlled VOC emissions

[19] Sites w/ tanks: > 6 tpy VOC emissions from highest emitting tank; for sites w/out tanks: > 6 tpy controlled VOC emissions

5.5 Montana

Fugitive emissions requirements in Montana are provided in the Administrative Rules of Montana (ARM) Title 17, Chapter 8, Subchapters 16 and 17.[20] A summary of Montana's requirements is presented in Table 11.

Table 11. Summary of Fugitive Emissions Requirements in Montana

Regulation	ARM 17.8.1601 through 17.8.1713
Effective Date	April 7, 2006
Monitoring Instrument	AVO
Leak Definition	NA
Initial Monitoring	
- *Well Sites*	30 days
- *Compressor Stations*	
Monitoring Frequency	
- *Well Sites*	Monthly
- *Low Production Wells*	
- *Compressor Stations*	NA
Repair	
- *First Attempt*	As soon as practicable
- *Final Repair*	15 days
- *Resurvey*	NA
- *DOR Deadline*	Next shutdown
- *Additional DOR Info*	NA

Subchapter 16 addresses well sites prior to the issuance of a permit, and subchapter 17 addresses permitted facilities. For both types of facilities, Montana requires monthly AVO inspections of VOC piping components. Operators must first attempt to repair a leak within 5 days after detection, with final repair completed within 15 days. DOR provisions are included when the repair requires a shutdown. In those situations, operators are given until the next scheduled shutdown to repair the leak. Table 12 provides a summary of the criteria evaluated for equivalency and the determination of equivalency of Montana's fugitive emissions requirements to the 2018 Proposal.

[20] Montana regulations available at http://deq.mt.gov/DEQAdmin/dir/legal/Chapters/ch08-toc.

Table 12. Equivalency of Montana's Fugitive Emissions Requirements to 2018 Proposal

Regulation	ARM 17.8.1601 through 17.8.1713
Effective Date	April 7, 2006
Monitoring Instrument	AVO
Leak Definition	No
Initial Monitoring	
- *Well Sites*	Yes
- *Compressor Stations*	
Monitoring Frequency	
- *Well Sites*	Yes
- *Low Production Wells*	
- *Compressor Stations*	NA
Repair	
- *First Attempt*	Yes
- *Final Repair*	
- *Resurvey*	No
- *DOR Deadline*	

5.6 New Mexico

Title 19, Chapter 15, Part 2 of the New Mexico Administrative Code (NMAC) prevents production operators from allowing gas to "either leak or escape from … wells, tanks, containers, pipe or other storage, conduit, or operating equipment."[21] However, we were unable to determine how these requirements are enforced. Therefore, we are not able to evaluate equivalency of these requirements to the 2018 Proposal.

5.7 North Dakota

Chapter 33-15-07 of the North Dakota Administrative Code (N.D.A.C.) states that operators must prevent the release of VOC,[22] and this requirement is enforced through company-wide consent decrees. A summary of North Dakota's fugitive emissions requirements is provided in Table 13.

[21] NMAC 19.15.2.8(B); available at http://www.emnrd.state.nm.us/OCD/documents/SearchablePDFofOCDTitle19Chapter15-Revised10-5-16.pdf.
[22] N.D.A.C. § 33-15-07-02(1); available at http://www.legis.nd.gov/information/acdata/pdf/33-15-07.pdf

Table 13. Summary of Fugitive Emissions Requirements in North Dakota

Regulation	N.D.A.C. § 33-15-07-02(1), enforced by Consent Decrees	
Effective Date	October 17, 2016	
Monitoring Instrument	OGI	Other approved
Leak Definition	Visible leak	State-defined
Initial Monitoring		
- *Well Sites*	Complete by December 31, 2016	
- *Compressor Stations*		
Monitoring Frequency		
- *Well Sites*	Semiannual	
- *Low Production Wells*	NA	
- *Compressor Stations*		
Repair		
- *First Attempt*	5 calendar days	
- *Final Repair*	30 calendar days	
- *Resurvey*	Included in final repair	
- *DOR Deadline*	"Difficult to repair" components must be repaired by the end of the consent decree term (two years) or during next scheduled shutdown or well shut-in, whichever is sooner	
- *Additional DOR Info*	Must notify North Dakota Department of Public Health	

The consent decree required the completion of initial monitoring by the end of 2016 at well sites, with monthly AVO and semiannual OGI inspections occurring thereafter. Low-production wells are excluded from these regular monitoring requirements, where low production is defined as producing less than 15 barrels (bbl) per day. Operators must attempt leak repairs within 5 days of detection, and repairs must be completed within 30 days, with a resurvey required upon completing the repair. If components are difficult to repair, the operator may repair them by the end of the consent decree term (2 years) or during the next schedule shutdown or well shut-in, whichever is sooner. Records of each monitoring survey, when each survey took place, equipment inspected, leaks found, and the repair fate of the leaks, including DOR, are also required. Based on discussions with state regulators, approximately 9,000 wells are subject to this consent decree.[23]

Table 14 provides a summary of the criteria evaluated for equivalency and determination of equivalency of North Dakota's fugitive emissions requirements to the 2018 Proposal. However, we are not determining these requirements to be equivalent because by their nature, consent decrees are negotiated terms for non-compliance and contain an expiration date, after which sources return to compliance with the underlying regulatory provisions, permit terms, etc. Further, inclusion of settlement terms from a consent decree as an alternative standard would essentially endorse regulation through enforcement as a pathway to the establishment of

[23] Conversation with Jim Semerad, North Dakota Department of Health. September 11, 2017.

alternative standards. For these reasons, the EPA believes that evaluation of settlement agreement terms reached through negotiated resolution to an enforcement action would be an inappropriate basis from which to determine equivalency for regulations promulgated through notice and comment rulemaking.

Table 14. Equivalency of North Dakota's Fugitive Emissions Requirements to 2018 Proposal

Regulation	N.D.A.C. § 33-15-07-02(1), enforced by Consent Decrees
Effective Date	October 17, 2016
Monitoring Instrument	OGI
Leak Definition	Yes
Initial Monitoring	
- *Well Sites*	Yes
- *Compressor Stations*	
Monitoring Frequency	
- *Well Sites*	Yes
- *Low Production Wells*	No
- *Compressor Stations*	
Repair	
- *First Attempt*	Yes
- *Final Repair*	
- *Resurvey*	
- *DOR Deadline*	

5.8 Ohio

On April 4, 2014, the Ohio EPA approved general permits 12.1 and 12.2 for well sites with small and large flares, respectively, that have conducted high-volume horizontal hydraulic fracturing.[24] These permits only apply to well sites that emit less than 1 tpy of any hazardous air pollutant (HAP), excluding those subject to 40 CFR Part 63, Subpart HH.[25] The fugitive emissions requirements in these permits are referred to as leak detection and repair (LDAR), and are the same for both permits. Ohio also approved general permit 18.1 for equipment leaks at natural gas compressor stations on February 7, 2017.[26] This permit applies to facilities that have the potential to emit 10.56 tpy of VOC or greater from fugitive equipment leaks. A summary of Ohio's fugitive emissions requirements is provided in Table 15.

[24] Ohio well site permits available at http://epa.ohio.gov/dapc/genpermit/oilandgaswellsiteproduction.aspx
[25] National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities
[26] Available at http://epa.ohio.gov/dapc/genpermit/ngcs/GP_181.aspx

Table 15. Summary of Fugitive Emissions Requirements in Ohio

Permit	General Permits 12.1 and 12.2		General Permit 18.1	
Effective Date	April 14, 2014		February 7, 2017	
Monitoring Instrument	OGI	Method 21	OGI	Method 21
Leak Definition	Visible leak	500 or 10,000 ppm	Visible leak	500, 2,000, or 10,000 ppm[a27]
Initial Monitoring				
- *Well Sites*	90 days		NA	
- *Compressor Stations*	NA		60 days	
Monitoring Frequency				
- *Well Sites*	Quarterly for 1 year, then semiannual or annual (based on 2% leak rate)		NA	
- *Low Production Wells*				
- *Compressor Stations*	NA		Quarterly	
Repair				
- *First Attempt*	5 calendar days		As soon as practicable	
- *Final Repair*	30 calendar days		30 calendar days	
- *Resurvey*	Within repair timeframe		Within repair timeframe	
- *DOR Deadline*	40 CFR § 60.5416(c)(5)		40 CFR § 60.5397a(h)(2)	
- *Additional DOR Info*	NA		NA	

[a] When using Method 21, leak definitions vary depending on component: for compressors and closed vent systems (CVS), the leak definition is 500 ppm, and for all other equipment, the leak definition is 10,000 ppm.

Each permittee for well sites is required to develop and implement an LDAR program for ancillary equipment that requires monitoring using OGI or Method 21. The permits do not appear to allow for alternative instrument monitoring methods. Initial monitoring is required within 90 days of startup followed by quarterly monitoring for a period of 1 year. After the first year, if less than 2% of components are found to be leaking, then the monitoring frequency is reduced to semiannual. If less than 2% of components are found to be leaking after two semiannual inspections, then the monitoring frequency can be reduced to annual. However, if the percent of components leaking during any subsequent monitoring events is equal to or greater than 2%, the monitoring frequency is reset to quarterly for a 1-year period before less frequent monitoring can be utilized.. When using OGI, leaks are defined as visible emissions. When using Method 21, leak definitions vary depending on component: for compressors and closed vent systems (CVS), the leak definition is 500 ppm, and for all other equipment, the leak definition is 10,000 ppm. Open-ended lines (OEL) must be equipped with a cap, blind flange, plug, or a second valve. Permittees must make a first attempt at repair within 5 days of detection of a leak, and the repair must be completed within 30 days after detection. If leaks cannot be repaired

[27] When using Method 21, leak definitions vary depending on component: for compressors and closed vent systems (CVS), the leak definition is 500 ppm, and for all other equipment, the leak definition is 10,000 ppm.

within that time frame, the general permit references the DOR provisions allowed under the 2012 NSPS OOOO, which require completion of delayed repairs at the end of the next shutdown.[28]

The requirements for compressor stations are similar to those for well sites, with a few exceptions. Initial monitoring must be completed by June 3, 2017 or within 60 days of startup, with subsequent monitoring on a quarterly basis. Intermittent/snap-acting pneumatic controllers are included in the list of ancillary equipment, and a separate leak definition of 2,000 ppm is provided for pumps. The permit requires operators to begin repairs as soon as practicable upon detection, with completion of repairs within 30 days. If leaks cannot be repaired within that time frame, the general permit references the DOR provisions allowed under the 2016 NSPS OOOOa. The permit also requires weekly AVO inspections when operators are present at a facility and the facility is operating.

Table 16 provides a summary of the criteria evaluated for equivalency and our determination of equivalency of Ohio's fugitive emissions requirements to the 2018 Proposal.

Table 16. Equivalency of Ohio's Fugitive Emissions Requirements to 2018 Proposal

Permit	General Permits 12.1 and 12.2		General Permit 18.1	
Effective Date	April 14, 2014		February 7, 2017	
Monitoring Instrument	OGI	Method 21	OGI	Method 21
Leak Definition	Yes	500 ppm – Yes	Yes	500 ppm - Yes
Initial Monitoring				
- *Well Sites*	No		NA	
- *Compressor Stations*	NA		Yes	
Monitoring Frequency				
- *Well Sites*	Yes		NA	
- *Low Production Wells*				
- *Compressor Stations*	NA		Yes	
Repair				
- *First Attempt*	Yes		Yes	
- *Final Repair*				
- *Resurvey*				
- *DOR Deadline*	No[29]			

[28] The specific requirements in the 2012 NSPS OOOO (at 40 CFR 60.5416(c)(5)) are limited to emissions detected on closed vent systems associated with storage vessels, however, it is our understanding that Ohio applies these same requirements for all affected components under the permit program.
[29] GPs 12.1 and 12.2 refer to DOR provisions in the 2012 NSPS OOOO.

5.9 Oklahoma

The Oklahoma Administrative Code (OAC) prohibits leakage from wellhead connections, surface equipment, and tank batteries (OAC 165:10-3-12), as well as any other gaseous waste at well sites (OAC 165:10-3-14). In addition, OAC 252:100-7-60.5(a)(2)(A) requires that minor sources comply with the 2016 NSPS OOOOa.[30] We are not evaluating equivalency of the permit requirements for Oklahoma because the current requirements incorporate the 2016 NSPS OOOOa.

5.10 Pennsylvania

5.10.1 General Permits 5 and 5A

On June 7, 2018, the Pennsylvania Department of Environmental Protection (PADEP) finalized General Permits 5 and 5A[31] for compressor stations and unconventional well sites, respectively, with an effective date of August 8, 2018. A summary of the fugitive emissions requirements within each permit is provided in Table 17.

Table 17. Summary of Permit Fugitive Emissions Requirements in Pennsylvania

Permit	General Permit 5			General Permit 5A		
Effective Date	August 8, 2018			August 8, 2018		
Monitoring Instrument	OGI	EPA Method 21	Other approved	OGI	EPA Method 21	Other approved
Leak Definition	Visible leak	500 ppm	State-defined	Visible leak	500 ppm	State-defined
Initial Monitoring						
- *Well Sites*	NA			60 days		
- *Compressor Stations*	60 days			NA		
Monitoring Frequency						
- *Well Sites*	NA			Quarterly (unconventional wells)		
- *Low Production Wells*						
- *Compressor Stations*	Quarterly			NA		
Repair						
- *First Attempt*	5 days			5 days		
- *Final Repair*	15 days			15 days		
- *Resurvey*	30 days			30 days		
- *DOR Deadline*	Next blowdown, with final repair within 2 years			Next blowdown, with final repair within 2 years		
- *Additional DOR Info*	If parts are ordered, repair within 10 days or receipt			If parts are ordered, repair within 10 days or receipt		

[30] Oklahoma regulations available at: www.oar.state.ok.us/.
[31] Pennsylvania's General Permits 5 and 5A available at http://www.dep.pa.gov/Business/Air/BAQ/Permits/Pages/GeneralPermits.aspx

The requirements for the two permits are the same. Monitoring must begin within 60 days of startup, and follow a quarterly instrument monitoring schedule. Operators must use OGI, Method 21 at 500 ppm, or other approved device to detect gaseous hydrocarbon leaks. Operators must first attempt to repair leaks within 5 days of detection, with final repairs being made within 15 days. Components must be resurveyed within 30 days of the final repair. DOR provisions are included for situations where a shutdown is required or if parts are needed to make repairs. The general permits also require monthly AVO inspections.

Table 18 provides a summary of the criteria evaluated for equivalency and our determination of equivalency of Pennsylvania's permit fugitive emissions requirements to the 2018 Proposal.

Table 18. Equivalency of Pennsylvania's Permit Fugitive Emissions Requirements to 2018 Proposal

Permit	General Permit 5		General Permit 5A	
Effective Date	August 8, 2018		August 8, 2018	
Monitoring Instrument	OGI	EPA Method 21	OGI	EPA Method 21
Leak Definition	Yes	Yes	Yes	Yes
Initial Monitoring				
- *Well Sites*	NA		Yes	
- *Compressor Stations*	Yes		NA	
Monitoring Frequency				
- *Well Sites*	NA		Yes	
- *Low Production Wells*				
- *Compressor Stations*	Yes		NA	
Repair				
- *First Attempt*	Yes		Yes	
- *Final Repair*				
- *Resurvey*				
- *DOR Deadline*	Other state-approved monitoring instruments		Other state-approved monitoring instruments	

5.10.2 Exemption No. 38

Exemption No. 38 of the Air Quality Permit Exemption List applies to unconventional well sites.[32] The PADEP has also finalized updates to this exemption, but we did not identify any changes from the current fugitive requirements.[33] Components included in the exemption's fugitive emissions requirements are connectors, flanges, storage vessels, valves, and compressor

[32] Exemption available at http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf.
[33] Proposed exemption available at http://www.dep.pa.gov/business/air/pages/methane-reduction-strategy.aspx.

seals in natural gas or hydrocarbon liquids service. The exemption requires monitoring within 60 days of startup and annually thereafter. Monitoring may be conducted using OGI, gas leak detectors, or other state approved methods. Leaks are defined as "no detectable emissions"[34] if using Method 21, 500 ppm if using a gas leak detector, and visible leaks if using OGI. All leaks must be repaired within 15 days of finding the leak. The exemption also includes DOR provisions for when a shutdown is necessary or if parts are needed. However, we were unable to determine any specific requirements related to when delayed repairs must be completed from the information available at the time of our analysis.

We have not determined whether the requirements in Exemption No. 38 are equivalent to those in the 2018 Proposal, though we are soliciting comment in the preamble on whether or not a state would revert back to its original program once the monitoring frequency for well sites is reduced. A summary of the requirements contained in the exemption is presented in Table 19.

Table 19. Summary of Fugitive Emissions Requirements in Pennsylvania's Exemption No. 38

Regulation	Exemption No. 38		
Effective Date	December 11, 2015		
Monitoring Instrument	OGI	Gas analyzer	Other approved
Leak Definition	Visible leak	500 ppm	State-defined
Initial Monitoring			
- *Well Sites*	60 days		
- *Compressor Stations*	NA		
Monitoring Frequency			
- *Well Sites*	Annual (for unconventional wells)		
- *Low Production Wells*			
- *Compressor Stations*	NA		
Repair			
- *First Attempt*	NA		
- *Final Repair*	15 days		
- *Resurvey*	NA		
- *DOR Deadline*	Next shutdown		
- *Additional DOR Info*	DOR provision if parts are ordered, but no requirements on repair timeline		

[34] Defined as a local VOC concentration at the surface of a leak source, adjusted for local VOC ambient concentration, that is less than 2.5 percent of the specified leak definition concentration. that indicates that a VOC emission (leak) is not present.

5.11 Texas

There are three sets of fugitive emissions requirements that may apply to well sites in Texas: the Permit by Rule (PBR) requirements and two Standard Permit requirements. The PBR requirements may be applied to well sites that emit less than 25 tpy of VOC, while those that emit higher amounts may be required to follow the Standard Permit requirements. The PBR requirements are found within the Texas Administrative Code (TAC),[35] and the Standard Permits can be found within either the TAC[36] or the "Air Quality Standard Permit for Oil and Gas Handling and Production Facilities".[37] A summary of the fugitive emissions requirements in Texas are presented in Table 20.

[35] 30 TAC § 106.352(e)(6); available at https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=106&rl=352.

[36] 30 TAC § 106.620; available at https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=116&rl=620

[37] Texas "Air Quality Standard Permit for Oil and Gas Handling and Production Facilities" available at https://www.tceq.texas.gov/assets/public/permitting/air/Announcements/oilgas-sp.pdf.

Table 20. Summary of Fugitive Emissions Requirements in Texas

Regulation/Permit	30 TAC § 106.352(e)(6)	Standard Permit	30 TAC § 106.620
Effective Date	February 27, 2011	November 8, 2012	September 4, 2000
Monitoring Instrument	(Not specified)	Method 21	Gas Analyzer
Leak Definition	NA	500 or 10,000 ppm	500, 2,000, or 10,000 ppm
Initial Monitoring			
- *Well Sites*	90 days	90 days	90 days
- *Compressor Stations*			
Monitoring Frequency			
- *Well Sites*	Quarterly, with potential to reduce to annual if % leaking valves is low	Quarterly, with potential to reduce to annual if % leaking valves is low	Quarterly, with potential to reduce to annual if % leaking valves is low
- *Low Production Wells*			
- *Compressor Stations*	NA	NA	NA
Repair			
- *First Attempt*	NA	5 days	NA
- *Final Repair*	30 - 60 days	15 days	15 days
- *Resurvey*	15 days	NA	NA
- *DOR Deadline*	Next shutdown	Next shutdown	Next scheduled shutdown
- *Additional DOR Info*	If repair would create more emissions, repair during next shutdown	If repair would create more emissions, repair during next shutdown	NA

The PBR and Standard Permit fugitive requirements apply to connectors, flanges, OEL, PRD, thief hatches, valves, and agitator, compressor, and pump seals. The PBR does not specify a monitoring instrument for conducting fugitive emissions monitoring while the standard permit requires Method 21 (or a gas analyzer in the TAC version). For the standard permit, if site-wide emissions are less than 25 tpy VOC, then the leak definition is 10,000 ppm. If site-wide emissions are greater than or equal to 25 tpy VOC, then the leak definition is 500 ppm. In the TAC version of the standard permit, the leak definition varies based on the component, the site-wide emissions, and the facility's proximity to an off-plant receptor (e.g., a residential area). Texas does not require separate initial monitoring for fugitive emissions, though regular quarterly instrument monitoring is required. The PBR and Standard Permit also allow for well sites to reduce their monitoring frequency to annual if the percentage of leaking valves at the site is low. If a leak is detected, operators must begin repair of the leak within 5 days if operating under the Standard Permit, and the timeline for repair completion can range from 15 to 60 days depending on the specific requirements for the site. DOR provisions are included for when a

shutdown or blowdown is necessary. In these situations, operators are required to complete the repair during the next scheduled shutdown.

Table 21 provides a summary of the criteria evaluated for equivalency and our determination of equivalency of Texas's fugitive emissions requirements to the 2018 Proposal. It is difficult to draw a conclusion of equivalency for the PBR because that program does not specify a monitoring instrument.

Table 21. Equivalency of Texas Fugitive Emissions Requirements to 2018 Proposal

Regulation/Permit	30 TAC § 106.352(e)(6)	Standard Permit	30 TAC § 106.620
Effective Date	February 27, 2011	November 8, 2012	September 4, 2000
Monitoring Instrument	(Not specified)	Method 21	Gas Analyzer
Leak Definition	No	500 ppm - Yes	2,000 ppm - Yes[38]
Initial Monitoring			
- *Well Sites*	No	No	No
- *Compressor Stations*	NA	NA	NA
Monitoring Frequency			
- *Well Sites*	Yes	Yes	Yes
- *Low Production Wells*			
- *Compressor Stations*	NA	NA	NA
Repair			
- *First Attempt*	Yes	Yes	Yes
- *Final Repair*			
- *Resurvey*	No	No	No
- *DOR Deadline*	Yes	Yes	Yes

5.12 Utah

The Utah Department of Environmental Quality (UDEQ) approved a "General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery" on June 5, 2014[39] and has also finalized PBR fugitive emissions requirements for certain well sites within the Utah Administrative Code, with an effective date of March 2, 2018.[40] A summary of Utah's fugitive emissions requirements is provided in Table 22.

[38] If Method 21 is used as the instrument monitoring
[39] Utah General Approval Order available at http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf.
[40] Utah Admin. Code r. 307-509. Final rule text available at https://www.utah.gov/pmn/files/359797.pdf#page=2

Table 22. Summary of Fugitive Emissions Requirements in Utah

Regulation	General Approval Order			Utah Admin. Code r. 307-509	
Effective Date	June 5, 2014			March 2, 2018	
Monitoring Instrument	OGI	Method 21	TDLAS	OGI	Method 21
Leak Definition	Visible leak	500 ppm	500 ppm	Visible leak	500 ppm
Initial Monitoring					
- *Well Sites*	90 days			60 days	
- *Compressor Stations*	NA			NA	
Monitoring Frequency					
- *Well Sites*	Annual if production ≥ 10,000 bbl/a; Quarterly if production ≥ 25,000 bbl/a and storage vessel present.			Semiannual if uncontrolled storage tank and dehydrators emissions > 4 tpy VOC	
- *Low Production Wells*					
- *Compressor Stations*	NA			NA	
Repair					
- *First Attempt*	5 days			NA	
- *Final Repair*	15 days			15 days	
- *Resurvey*				30 days	
- *DOR Deadline*	Next shutdown, with final repair within 6 months			Next shutdown or shut-in, after a vent blowdown, or within 2 years, whichever is earlier	
- *Additional DOR Info*	If parts are ordered, repair within 15 days of receipt			Unsafe to repair during operation of the unit	

The General Approval Order (GAO) requires LDAR for components (compressors, connectors, flanges, PRDs, valves, pumps, other vents, process drains, pump seals, compressor seals, access door seals, and other seals that contain or contact a process stream with hydrocarbons) based on the annual throughput of crude oil and condensate, as well as the equipment present at the site. Annual instrument monitoring is required for sources that have a throughput greater than or equal to 10,000 bbl and for sources that do not have a crude oil or condensate storage tank on site. Quarterly instrument monitoring is required for sources that have a throughput greater than or equal to 25,000 bbl. For sources subject to quarterly monitoring, provisions are available for reduced monitoring frequency if no leaks are found within a single year monitoring timeframe. Repairs must be made within 15 days of finding a leak. DOR is allowed if replacement parts are unavailable (parts must be ordered within 5 days of detection and repairs must be completed within 15 days after receipt of the parts) or technically infeasible to repair without a shutdown (shutdown must occur within 6 months of finding leak or operators must demonstrate emissions from shutdown would be greater than the uncontrolled leaking component). The monitoring can be performed using Method 21, a tunable diode laser absorption spectroscopy (TDLAS) or OGI. A leak is defined as a reading of 500 ppm with Method 21 or TDLAS, or a visible leak with OGI.

Operators had the option to comply with the requirements of the GAO, or they could have obtained a source-specific approval order (i.e., Utah's version of a permit) from UDEQ. No well sites have operated under this GAO, and the state is no longer accepting applications under the order. Of the source-specific approval orders that have been issued, all require at least annual monitoring. With UDEQ's PBR rules, well sites that are not major sources[41] will no longer be able to apply for source-specific approval orders and must comply with the PBR requirements. When complying with these requirements, well sites must also register with the state, as required by Utah Admin. Code r. 307-505. It should be noted that neither the GAO nor the PBR apply to compressor stations, which are covered by source-specific approval orders that differ in their requirements among sites.

The fugitive emissions requirements in the PBR only cover well sites where uncontrolled storage vessel and dehydrator emissions are greater than 4 tpy. The requirements cover most of the components included in the 2018 Proposal (except for storage vessels) and allow for OGI or Method 21 monitoring with a leak definition of 500 ppm. Monitoring must be conducted 60 days after startup and semiannually thereafter. Operators have 15 days to repair a leak after detection and must resurvey the components 30 days after the leak is repaired. DOR provisions are included if a shutdown or vent blowdown is needed to repair a leak or if it is unsafe to repair during operation of the unit. In these situations, operators have until the next shutdown or 2 years to repair the leak, whichever is earlier. Table 23 provides a summary of the criteria evaluated for equivalency and our preliminary evaluation of equivalency of Utah's fugitive emissions requirements to the 2018 Proposal. Since no operators have elected to comply with the GAO requirements and the opportunity to apply to do so has closed, we do not think it is appropriate to conclude the GAO is equivalent.

[41] As defined in Utah Admin. Code r. 307-101-2

Table 23. Equivalency of Utah's Fugitive Emissions Requirements to 2018 Proposal

Regulation	General Approval Order		Utah Admin. Code r. 307-509	
Effective Date	June 5, 2014		March 2, 2018	
Monitoring Instrument	OGI	Method 21	OGI	Method 21
Leak Definition	Yes	Yes	Yes	Yes
Initial Monitoring				
- *Well Sites*	No		Yes	
- *Compressor Stations*	NA		NA	
Monitoring Frequency				
- *Well Sites*	No (only applies to well sites with annual production > 10,000 bbl)		Yes (sites where uncontrolled storage tank and dehydrators emissions > 4 tpy VOC)	
- *Low Production Wells*				
- *Compressor Stations*	NA		NA	
Repair				
- *First Attempt*	Yes		Yes	
- *Final Repair*				
- *Resurvey*				
- *DOR Deadline*				

5.13 West Virginia

Permits issued for well sites and compressor stations in West Virginia require compliance with the fugitive emissions requirements in the 2016 NSPS OOOOa.[42] This requirement is found in section 12 of the Class II General Permit G70-D for well sites, and in section 16 of the Class II General Permit G35-D for compressor stations. Before the 2016 NSPS OOOOa, West Virginia had separate fugitive emissions requirements for well sites in sections 4.1.3 through 4.2 of the Class II General Permit G70-B. Those previous permits required quarterly monitoring with AVO, Method 21 (at a leak definition of 500 ppm), OGI, or a combination of the three and applied to valves, above-ground piping, and pumps. Operators were required to complete the repair within 15 days of finding a leak, with a first attempt made within 5 days. No resurvey requirements were included. DOR provisions were included for situations where a shutdown would be required to repair a leak or if emissions would be higher as a result of repairing the leak without the delay. For these situations, operators were required to repair the leak during the next shutdown.

We are not evaluating equivalency of the permit requirements for West Virginia because the current requirements incorporate the 2016 NSPS OOOOa.

5.14 Wyoming

The Wyoming Department of Environmental Quality (Wyoming DEQ) issued regulations in June 2015 for existing (as of January 1, 2014) PAD facilities (locations where more than one

[42] West Virginia permits available at http://dep.wv.gov/daq/permitting/Pages/airgeneralpermit.aspx.

well and/or associated production equipment are located, where some or all production equipment is shared by more than one well or where well streams from more than one well are routed through individual production trains at the same location), single-well oil and gas production facilities or sources, and all compressor stations that are located in the Upper Green River Basin (UGRB) ozone nonattainment area.[43] A summary of the Wyoming requirements is presented in Table 24.

Table 24. Summary of Fugitive Emissions Requirements in Wyoming

Regulation	020-002-008 Wyo. Code R. § 6(g)	
Effective Date	December 20, 2016	
Monitoring Instrument	OGI	Method 21
Leak Definition	State-defined	State-defined
Initial Monitoring		
- *Well Sites*	90 days	
- *Compressor Stations*		
Monitoring Frequency		
- *Well Sites*	Quarterly (UGRB with site-wide emissions ≥ 4 tpy VOC)	
- *Low Production Wells*		
- *Compressor Stations*		
Repair		
- *First Attempt*	NA	
- *Final Repair*		
- *Resurvey*		
- *DOR Deadline*		
- *Additional DOR Info*		

The Wyoming DEQ rule requires operators with fugitive emissions greater than or equal to 4 tpy of VOC to develop and implement an LDAR protocol. The deadline for development of this protocol was January 1, 2017. Operators are required to monitor components (flanges, connectors (other than flanges), OELs, pumps, valves, and "other" components listed in Table 2-4 of the EPA's Protocol for Equipment Leak Emissions Estimates) quarterly using a combination of Method 21, OGI, other instrument based technologies, or AVO inspections. No specific repair deadlines are included in the regulation. Table 25 provides a summary of the criteria evaluated for equivalency and determination of equivalency of Wyoming's fugitive emissions requirements to the 2018 Proposal. However, due to the flexibility of the requirements, we are unable to include alternative fugitive standards relative to these requirements.

[43] Wyoming regulations are available at https://rules.wyo.gov/.

Table 25. Equivalency of Wyoming's Fugitive Emissions Requirements to 2018 Proposal

Regulation	020-002-008 Wyo. Code R. § 6(g)	
Effective Date	December 20, 2016	
Monitoring Instrument	OGI	Method 21
Leak Definition	Yes	No
Initial Monitoring		
- *Well Sites*	No	
- *Compressor Stations*		
Monitoring Frequency		
- *Well Sites*	Yes (for UGRB with site-wide emissions > 4 tpy VOC)	
- *Low Production Wells*		
- *Compressor Stations*		
Repair		
- *First Attempt*	No	
- *Final Repair*		
- *Resurvey*		
- *DOR Deadline*		

6.0 CONCLUSIONS

Based on the analysis presented in section 5.0, we are proposing that fugitive emissions requirements related to monitoring, repair, and recordkeeping are equivalent to the 2018 Proposal for the following state programs:

- California Code of Regulations, title 17, §§95665-95667, effective January 1, 2020;
- Colorado Regulation 7, §§XII.L, effective June 30, 2018, or XVII.F, effective October 15, 2014 for well sites and January 1, 2015 for compressor stations;
- Ohio General Permits 12.1 and 12.2, effective April 14, 2014;
- Ohio General Permit 18.1, effective February 7, 2017;
- Pennsylvania General Permit 5, effective January 16, 2015;
- Texas Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, effective November 8, 2012, or at 30 Texas Administrative Code §116.620, effective September 4, 2000; and
- Utah Administrative Code R307-509, effective March 2, 2018.

For reasons stated in section 5.0 and summarized here, we are unable to determine equivalency of the fugitive emissions requirements for the following state programs:

- Administrative Rules of Montana Title 17, Chapter 8, Subchapters 16 and 17 because instrument monitoring is not required.
- New Mexico Administrative Code Title 19, Chapter 15, Part 2 because we were unable to determine the enforcement mechanism.

- North Dakota Administrative Code Chapter 33-15-07 because of the temporary nature of the Consent Decrees used to enforce these requirements.
- Wyoming Administrative Rules Reference No. 020.0002.8.12202016 because of the flexibility of the requirements.

Finally, the following states either incorporate the fugitive emissions requirements in the 2016 NSPS OOOOa or do not have requirements that we were able to evaluate:

- Alaska
- Oklahoma
- West Virginia

MEMORANDUM

TO: EPA Docket ID No. EPA-HQ-OAR-2017-0483

DATE: April 12, 2018

SUBJECT: Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Proposed Standards at 40 CFR Part 60, Subpart OOOOa

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1.0 INTRODUCTION

This memorandum summarizes the requirements of various state fugitive emissions programs for well sites and compressor stations. It compares each state programs' requirements to the proposed revisions to the Oil and Natural Gas Sector New Source Performance Standards (NSPS) at 40 CFR Part 60, Subpart OOOOa.

2.0 BACKGROUND

On June 3, 2016, the EPA published a final rule titled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources" in the **Federal Register** ("2016 NSPS OOOOa"). This rule introduced fugitive emissions requirements for the collection of fugitive emissions components located at well sites and compressor stations. The EPA has granted reconsideration of several issues in the 2016 NSPS OOOOa, including the fugitive emissions requirements and the process and criteria for requesting and receiving approval for the use of an alternative means of emission limitation (AMEL). To support the proposed reconsideration of the 2016 NSPS OOOOa ("2018 Proposal"), EPA evaluated the equivalence of existing state programs to the fugitive emissions requirements in the 2018 Proposal.

This memorandum details the process taken to evaluate equivalency of these existing programs and provides support for the proposed alternative fugitive standards contained in the 2018 Proposal. Section 3.0 provides a summary of the 2016 NSPS OOOOa and the proposed requirements in the 2018 Proposal. In section 4.0, we describe the methodology and criteria used for evaluating equivalency. Section 5.0 provides an evaluation of the existing programs that were included in this analysis. A summary of the conclusions of this analysis is included in section 6.0. Links to each of the programs evaluated in this analysis are provided in Appendix 1.

3.0 FUGITIVE EMISSIONS REQUIREMENTS IN 2016 NSPS OOOOa AND 2018 PROPOSAL

The 2016 NSPS OOOOa sets standards to control greenhouse gases (GHG) (in the form of limitations on methane) and volatile organic compound (VOC) emissions from fugitive emissions components at well sites and compressor stations. Specifically, owners and operators must conduct semiannual monitoring for fugitive emissions at well sites and quarterly monitoring for fugitive emissions at compressor stations. Additionally, well sites located on the Alaskan North Slope must conduct annual monitoring. This monitoring must be conducted using optical gas imaging (OGI), and repairs are required for any visible emissions observed. Method

21 of Appendix A-7 to Part 60 ("Method 21") may be used as an alternative monitoring method at a repair threshold level of 500 parts per million (ppm). Repairs must be made within 30 days of finding fugitive emissions, and a resurvey of the repaired component is required within 30 days of the repair using either OGI or Method 21. When using OGI for this resurvey, no visible emissions indicates successful repair. For Method 21, an instrument reading below 500 ppm indicates successful repair, or the presence of no visible emissions if using a soap solution. A monitoring plan that covers the collection of fugitive emissions components at a well site or compressor station within a company-defined area must be developed and implemented.

The 2018 Proposal includes amendments to these fugitive emissions standards. For instance, we are proposing to revise the monitoring frequency for well sites to semiannual for a 2-year period, followed by annual monitoring for well sites that are not considered low production well sites. For low production well sites, we are proposing annual monitoring. Low production well sites are well sites where the average combined oil and natural gas production is less than 15 barrels of oil equivalent (boe) per day, averaged over the first 30 days of production. The 2018 Proposal does not propose any changes to the quarterly monitoring for compressor stations. Additionally, we are proposing separate monitoring requirements for compressor stations located on the Alaskan North Slope (annual monitoring). The 2018 Proposal includes changes to the repair deadlines for fugitive emissions; specifically, a first attempt at repair is required within 30 days of finding fugitive emissions, with a final repair that includes the resurvey within 60 days of finding the fugitive emissions.

A summary of the fugitive emissions requirements within the 2016 NSPS OOOOa and the 2018 Proposal is provided in Table 1.

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Table 1. Summary of Fugitive Emissions Requirements in 2016 NSPS OOOOa and 2018 Proposal

Regulation	40 CFR Part 60, Subpart OOOOa			
	2016 NSPS OOOOa		2018 Proposal	
Monitoring Instrument	OGI	Method 21	OGI	Method 21
Leak Definition	Visible leak	500 ppm	Visible leak	500 ppm
Initial Monitoring				
- *Well Sites*	60 days		60 days	
- *Compressor Stations*				
Monitoring Frequency				
- *Well Sites*	Semiannual		Semiannual for two years and annual thereafter	
- *Low Production Wells*			Annual	
- *Compressor Stations*	Quarterly		Quarterly	
Repair				
- *First Attempt*	NA		30 days	
- *Final Repair*	30 days		60 days	
- *Resurvey*	30 days from repair		Included in final repair	
- *DOR Deadline*	Next scheduled shutdown, or 2 years		Next scheduled shutdown, or 2 years	

4.0 SUMMARY OF METHODOLOGY USED TO EVALUTATE EQUIVALENCY

This memorandum provides our evaluation of the fugitive emissions requirements for states with an existing fugitive emissions program. For this evaluation, we analyzed the components that were included in the fugitive emissions programs, the affected facilities, the effective date(s) of the program, approved monitoring instruments, fugitive emissions definitions, monitoring frequencies, repair and resurvey timelines, and delay of repair (DOR) provisions. Equivalency determinations were made by comparing each of these aspects to those of the 2018 Proposal and by considering the requirements in the broader context of their fugitive emissions programs. The states that we analyzed were selected based on programs that we reviewed in previous actions and through a review of regulations and permit information for other states with known oil and gas activities.

This analysis was limited to information from state programs that were publicly available at the time of production of this memorandum and may not include state programs that are currently being drafted or proposed. For this memorandum, we reviewed fugitive emission programs from Alaska, California, Colorado, Montana, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, Utah, West Virginia, and Wyoming. States that are not included in this analysis either do not have requirements, or we were unable to locate requirements for this analysis. A summary of each of the programs is provided in the following section.

5.0 ANALYSIS OF STATE FUGITIVE EMISSIONS REQUIREMENTS

5.1 Components

As mentioned in the previous section, this analysis began by examining the specific fugitive emissions components subject to the requirements in each state program. Only one state program (Wyoming) was identified that explicitly includes all the components that are included in the 2018 Proposal, although there are certain key components that are included in most of the state programs (connectors, flanges, pressure relief devices (PRDs), and valves). A comparison of the types of components included in the state programs and the 2018 Proposal is presented in Table 2.

5.2 Alaska

Title 18, Chapter 50 of the Alaska Administrative Code (AAC) adopts the 2012 NSPS OOOO requirements for Title V sources.[1] While this does not require fugitive emissions programs for well sites or compressor stations, in 2009, the state's Sub-Cabinet on Climate Change, within the Office of the Governor, recommended assessing the potential emissions reductions and costs associated with a fugitive emissions program.[2] We were unable to locate any additional information on this effort. Therefore, we are not able to evaluate equivalency of these requirements to the 2018 Proposal.

5.3 California

The California Air Resources Board (CARB) finalized fugitive emissions requirements for well sites and compressors stations on July 17, 2017, with an effective date of January 1, 2018.[3] A summary of California's fugitive emissions requirements is provided in Table 3.

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[1] 18 AAC 50.040(a)(2)(WW); available at http://www.legis.state.ak.us/basis/aac.asp#18.50.040.

[2] Alaska Climate Change Strategy's Mitigation Advisory Group Final Report: Greenhouse Gas Inventory and Forecast and Policy Recommendations Addressing Greenhouse Gas Reduction in Alaska (2009); available at http://climatechange.alaska.gov/mit/mag.htm

[3] California regulations available at https://govt.westlaw.com/calregs/Browse/Home/California/CaliforniaCodeofRegulations?guid=I401BB8146DA14B519A991D7827913AEE&originationContext=documenttoc&transitionType=Default&contextData=(sc.Default).

Table 2. Components Included in the 2018 Proposal and State Requirements

	2018 Proposal	California	Colorado	Montana[4]	North Dakota[5]	Ohio	Pennsylvania[6]	Texas[7]	Utah	Wyoming
Compressors	X				X	X	X	X	X	X
Connectors	X	X[8]	X		X	X	X	X	X	X
Covers	X				X	X	X		X	X
CVSs	X[9]				X	X	X		X	X
Flanges	X	X	X		X	X	X	X	X	X
Instruments	X				X		X		X	X
Meters	X[10]	X			X		X		X	X
OELs	X	X			X	X	X	X	X	X
PRDs	X	X	X		X	X	X	X	X	X
Storage Vessels	X[11]				X	X	X			X
Thief Hatches	X				X		X	X	X	X
Valves	X	X	X		X	X	X	X	X	X
(Other)	X	X	X	X	X	X	X	X	X	X

[4] Montana only requires inspection of "VOC piping components".
[5] The North Dakota consent decree does not provide a definition for components. For the analysis, EPA assumes all the 2018 Proposal components are included.
[6] Pennsylvania permit language does not list component types to be inspected. For this analysis, EPA assumes all of the 2018 Proposal components are included. Exemption No. 38 only includes connectors, covers, flanges, storage vessels, valves, and other components.
[7] Texas does not include definitions for "components" but mentions certain components in their requirements.
[8] "Threaded connection".
[9] Only includes those not subject to 40 CFR §§60.5397a or 60.5411a.
[10] Does not include meters owned by third-parties.
[11] Only includes those not subject to 40 CFR §60.5395a.

Table 3. Summary of Fugitive Emissions Requirements in California

Regulation	Cal. Code Regs. tit. 17, § 95665-95677	
Effective Date	January 1, 2018	January 1, 2020
Monitoring Instrument	Method 21	
Leak Definition	10,000 ppm	1,000 ppm
Initial Monitoring		
- *Well Sites*	90 days	
- *Compressor Stations*		
Monitoring Frequency		
- *Well Sites*	Quarterly	
- *Low Production Wells*		
- *Compressor Stations*		
Repair		
- *First Attempt*	NA	
- *Final Repair*	(See Table 4)	
- *Resurvey*	Within repair timeframe	
- *DOR Deadline*	Next process shutdown or 12 months, whichever is sooner	
- *Additional DOR Info*	If parts needed, repair within 30 days of required date; DOR if deemed critical to reliability of public gas system	

The regulated components include threaded connections, flanges, meters, OELs, PRDs, valves, fittings, process drains, stuffing boxes, pipes, seal fluid systems, diaphragms, hatches, sight-glasses, well casings, pneumatic devices, and reciprocating compressor rod packing and seals. Weekly audio-visual and quarterly Method 21 inspections are required. OGI may be used as a screening tool prior to using Method 21 for quarterly inspections. The repair requirements change for leaks that are detected on or after January 1, 2020 because of the phase-in period of the rule that extends from January 1, 2018 to December 31, 2019. The timeline for repair also depends on the ppm instrument reading observed during Method 21 monitoring, as presented in Table 4:

Table 4. California Timelines to Finish Leak Repair After Detection (Days)

	1,000-9,999 ppm	**10,000-49,999 ppm**	**50,000 ppm or greater**
Before 2020	(N/A)	14	5
2020 and After	14	5	2

Critical components[12] or critical process units[13] must be repaired during the next scheduled shutdown or within 12 months of detecting the leak, whichever is sooner. The regulations also include DOR provision for when parts are needed and for when a component is considered to be critical to the reliability of the public gas system. Components used exclusively for crude oil with an American Petroleum Institute (API) gravity less than 20 are exempt from the fugitive emissions requirements. Records of when the inspection took place, components found leaking, repair dates, and leak concentrations before and after repair are required. Annual reporting of the results of all weekly and quarterly inspections, including the initial and final concentrations of each component, are also required. The annual reporting form is included in Appendix 1.

Table 5 provides a summary of the criteria evaluated for equivalency and our equivalency determination of California's fugitive emissions requirements to the 2018 Proposal:

Table 5. Equivalency of California's Fugitive Emissions Requirements to 2018 Proposal

Regulation	Cal. Code Regs. tit. 17, § 95665-95677	
Effective Date	January 1, 2018	January 1, 2020
Monitoring Instrument	Method 21	
Leak Definition	No	1,000 ppm – Yes
Initial Monitoring		
- *Well Sites*	No	
- *Compressor Stations*		
Monitoring Frequency		
- *Well Sites*	Yes	
- *Low Production Wells*		
- *Compressor Stations*		
Repair		
- *Final Repair*	Yes	
- *Resurvey*	Yes	
- *DOR Deadline*	Yes	

5.4 Colorado

Fugitive emissions requirements for oil and gas facilities in Colorado are located in the state's Regulation 7.[14] There are two sets of fugitive emissions requirements: one for facilities in

[12] A component that would require the shutdown of a critical process unit if that component was shutdown/disabled
[13] A process unit or group of components that must remain in service because of its importance to the overall process that requires it to continue to operate, and has no equivalent equipment to replace it or cannot be bypassed, and it is technically infeasible to repair leaks from that process unit without shutting it down and opening the process unit to the atmosphere
[14] Colorado regulations available at https://www.sos.state.co.us/CCR/DisplayRule.do?action=ruleinfo&ruleId=2341&deptID=16&agencyID=7&deptNa

ozone nonattainment areas (section XII.L) and one that covers the entire state (section XVII.F). A summary of these two sets of requirements is presented in Table 6.

Table 6. Summary of Fugitive Emissions Requirements in Colorado

Regulation	Regulation 7, Section XII.L			Regulation 7, Section XVII.F		
Effective Date	June 30, 2018			October 15, 2014 (well sites); January 1, 2015 (compressor stations)		
Monitoring Instrument	OGI	Method 21	Other approved	OGI	Method 21	Other approved
Leak Definition	Visible leak	500 ppm	State-defined	Visible leak	500 ppm	Visible leak
Initial Monitoring						
- *Well Sites*	15-30 days			(See Table 8)		
- *Compressor Stations*	90 days			(See Table 9)		
Monitoring Frequency						
- *Well Sites*	Based on Volatile Organic Compound (VOC) emissions: tpy ≥ 1 and ≤ 6 – Annual; tpy > 6 – Semiannual			(See Table 7)		
- *Low Production Wells*						
- *Compressor Stations*	Quarterly					
Repair						
- *First Attempt*	5 working days			5 working days		
- *Final Repair*	30 working days			NA		
- *Resurvey*	15 days of repair			15 days of repair		
- *DOR Deadline*	Next scheduled shutdown, with final repair within 2 years			Next scheduled shutdown		
- *Additional DOR Info*	If parts are ordered, repair within 15 days of receipt; if other good cause, repair within 15 days after cause ceases to exist			If parts are ordered, repair within 15 days of receipt; if other good cause, repair within 15 days after cause ceases to exist		

Both programs regulate the following types of components: connectors, flanges, PRDs, vales, pump seals, and other openings on a controlled storage tank. Components in process streams consisting of glycol, amine, produced water, or methanol are not included in the programs. Instrument monitoring for leaks is required using Method 21, OGI, or a state approved instrument monitoring method (AIMM). Leaks are defined as a measured hydrocarbon concentration greater than 500 ppm when Method 21 is used, and as detectable emissions when

me=Department%20of%20Public%20Health%20and%20Environment&agencyName=Air%20Quality%20Control%20Commission&seriesNum=5%20CCR%201001-9

OGI or AIMM are used. Operators must make their first attempt to repair leaks within 5 days after detection, and components must be resurveyed within 15 days of repair in order to ensure that the components are no longer leaking. DOR provisions are also included for situations where a shutdown is required or if parts are unavailable. If the operator needs to order parts, the repair must be made within 15 days of receipt of those parts.

For facilities in ozone nonattainment areas, the effective date of the fugitive emissions requirements is June 30, 2018. Well sites must conduct initial monitoring within 15 to 30 days after startup, and compressor stations must conduct initial monitoring within 90 days after startup. For well sites, the monitoring frequency is dependent on the uncontrolled VOC emissions from the highest emitting storage tank at the well site. If no storage tanks are present, then the monitoring frequency is based on the controlled VOC emissions from the well site. If the emissions are 1 ton per year (tpy) or greater but less than 6 tpy, then annual instrument monitoring is required. If the emissions are 6 tpy or greater, then semiannual monitoring is required. For compressor stations, quarterly instrument monitoring is required, regardless of emissions. Operators are required to complete leak repairs within 30 days after detection for these areas. If a shutdown is required to make repairs, then repairs must be completed during the next scheduled shutdown, or within two years.

For the statewide fugitive emissions requirements, the effective dates are October 15, 2014, and January 1, 2015, for well sites and compressor stations, respectively. Similar to the ozone nonattainment area requirements, the instrument monitoring frequency for a well site is dependent on the VOC emissions and the equipment present at the well site. For compressor stations, the frequency is based on the fugitive VOC emissions from the compressor station. The different frequency requirements for each type of facility are presented in Table 7.

Table 7. Colorado State-Wide Instrument Monitoring Frequencies

	Frequency
Well sites without storage tanks: Controlled VOC emissions (tpy)	
- > 0 and ≤ 6	One-time
- > 6 and ≤ 12	Annually
- > 12 and ≤ 20	Quarterly
- > 20	Monthly
Well sites with storage tanks: Uncontrolled VOC emissions from highest emitting tank (tpy)	
- > 0 and ≤ 6	One-time
- > 6 and ≤ 12	Annually
- > 12 and ≤ 50	Quarterly
- > 50	Monthly
Compressor stations: Fugitive VOC emissions (tpy)	
- > 0 and ≤ 12	Annually
- > 12 and ≤ 50	Quarterly
- > 50	Monthly

Initial monitoring requirements for compressor stations and well sites are presented in Tables 8 and 9, respectively.

Table 8. Colorado State-Wide Compressor Station Initial Monitoring

	Fugitive VOC Emissions	
Construction Date	tpy > 0 and ≤ 50	tpy > 50
On or Before January 1, 2015	90	30
After January 1, 2015	(Upon startup)	

Table 9. Colorado State-Wide Well Site Initial Monitoring

	Instrument Monitoring Frequency		
Construction Date	One-Time	Monthly	Other
On or After October 15, 2014	15-30 days after startup		
Before October 15, 2014	By January 1, 2016	30 days	90 days

According to the statement of basis and purpose within Regulation 7, distinctions between well sites with storage tanks and those without were used to complement the state's Storage Tank Emissions Monitoring programs. A 2014 guidance memo also clarifies that tank

batteries are included in the Regulation 7 definition for a "well production facility". [15] Monthly audio-visual-olfactory (AVO) inspections are also required for well sites that do not conduct monthly instrument monitoring. If a shutdown is required to repair any instrument monitoring leak identified, the leak must be repaired during the next scheduled shutdown. The recordkeeping form is included in Appendix 1.

Table 10 provides a summary of the criteria evaluated for equivalency and our determination of equivalency of Colorado's fugitive emissions requirements to the 2018 Proposal.

Table 10. Equivalency of Colorado's Fugitive Emissions Requirements to 2018 Proposal

Regulation	Regulation 7, Section XII.L		Regulation 7, Section XVII.F	
Effective Date	June 30, 2018		October 15, 2014 (well sites); January 1, 2015 (compressor stations)	
Monitoring Instrument	OGI	Method 21	OGI	Method 21
Leak Definition	Yes	Yes	Yes	Yes
Initial Monitoring				
- *Well Sites*	Yes		Yes[16]	
- *Compressor Stations*	No		Yes (> 50 tpy VOC emissions or constructed after January 1, 2015)	
Monitoring Frequency				
- *Well Sites*	Yes[17]		Yes[18]	
- *Low Production Wells*	Yes (> 1 tpy uncontrolled VOC emissions)		Yes[19]	
- *Compressor Stations*	Yes		Yes (> 12 tpy fugitive VOC emissions)	
Repair				
- *First Attempt*	Yes		Yes	
- *Final Repair*			No	
- *Resurvey*			Yes	
- *DOR Deadline*			No	

[15] Laplante, C. and S. Rucker (2014). Guidance for Oil & Gas Industry Regulation 7, Section XVII.F, Leak Detection and Repair Program for Well Production Facilities and Natural Gas Compressor Stations and Section XVII.B, General Provisions for Open Ended Valves or Lines. Denver, CO, CDPHE Stationary Sources Program. Available at https://www.colorado.gov/pacific/cdphe/summary-oil-and-gas-emissions-requirements

[16] If well site was constructed before October 15, 2014, and does not have one-time or monthly monitoring, Colorado requirements are not considered equivalent

[17] For sites with > 6 tpy uncontrolled VOC emissions for the first two years and > 1 tpy thereafter

[18] First two years – sites w/ tanks: > 12 tpy VOC emissions from highest emitting tank, sites w/out tanks: > 12 tpy controlled VOC emissions; then sites w/ tanks: > 6 tpy VOC emissions from highest emitting tank; for sites w/out tanks: > 6 tpy controlled VOC emissions

[19] Sites w/ tanks: > 6 tpy VOC emissions from highest emitting tank; for sites w/out tanks: > 6 tpy controlled VOC emissions

5.5 Montana

Fugitive emissions requirements in Montana are provided in the Administrative Rules of Montana (ARM) Title 17, Chapter 8, Subchapters 16 and 17.[20] A summary of Montana's requirements is presented in Table 11.

Table 11. Summary of Fugitive Emissions Requirements in Montana

Regulation	ARM 17.8.1601 through 17.8.1713
Effective Date	April 7, 2006
Monitoring Instrument	AVO
Leak Definition	NA
Initial Monitoring	
- *Well Sites*	30 days
- *Compressor Stations*	
Monitoring Frequency	
- *Well Sites*	Monthly
- *Low Production Wells*	
- *Compressor Stations*	NA
Repair	
- *First Attempt*	As soon as practicable
- *Final Repair*	15 days
- *Resurvey*	NA
- *DOR Deadline*	Next shutdown
- *Additional DOR Info*	NA

Subchapter 16 addresses well sites prior to the issuance of a permit, and subchapter 17 addresses permitted facilities. For both types of facilities, Montana requires monthly AVO inspections of VOC piping components. Operators must first attempt to repair a leak within 5 days after detection, with final repair completed within 15 days. DOR provisions are included when the repair requires a shutdown. In those situations, operators are given until the next scheduled shutdown to repair the leak. Table 12 provides a summary of the criteria evaluated for equivalency and the determination of equivalency of Montana's fugitive emissions requirements to the 2018 Proposal.

[20] Montana regulations available at http://deq.mt.gov/DEQAdmin/dir/legal/Chapters/ch08-toc.

Table 12. Equivalency of Montana's Fugitive Emissions Requirements to 2018 Proposal

Regulation	ARM 17.8.1601 through 17.8.1713
Effective Date	April 7, 2006
Monitoring Instrument	AVO
Leak Definition	No
Initial Monitoring	
- *Well Sites*	Yes
- *Compressor Stations*	
Monitoring Frequency	
- *Well Sites*	Yes
- *Low Production Wells*	
- *Compressor Stations*	NA
Repair	
- *First Attempt*	Yes
- *Final Repair*	
- *Resurvey*	No
- *DOR Deadline*	

5.6 New Mexico

Title 19, Chapter 15, Part 2 of the New Mexico Administrative Code (NMAC) prevents production operators from allowing gas to "either leak or escape from … wells, tanks, containers, pipe or other storage, conduit, or operating equipment."[21] However, we were unable to determine how these requirements are enforced. Therefore, we are not able to evaluate equivalency of these requirements to the 2018 Proposal.

5.7 North Dakota

Chapter 33-15-07 of the North Dakota Administrative Code (N.D.A.C.) states that operators must prevent the release of VOC,[22] and this requirement is enforced through company-wide consent decrees. A summary of North Dakota's fugitive emissions requirements is provided in Table 13.

[21] NMAC 19.15.2.8(B); available at http://www.emnrd.state.nm.us/OCD/documents/SearchablePDFofOCDTitle19Chapter15-Revised10-5-16.pdf.
[22] N.D.A.C. § 33-15-07-02(1); available at http://www.legis.nd.gov/information/acdata/pdf/33-15-07.pdf

Table 13. Summary of Fugitive Emissions Requirements in North Dakota

Regulation	N.D.A.C. § 33-15-07-02(1), enforced by Consent Decrees	
Effective Date	October 17, 2016	
Monitoring Instrument	OGI	Other approved
Leak Definition	Visible leak	State-defined
Initial Monitoring		
- *Well Sites*	Complete by December 31, 2016	
- *Compressor Stations*		
Monitoring Frequency		
- *Well Sites*	Semiannual	
- *Low Production Wells*	NA	
- *Compressor Stations*		
Repair		
- *First Attempt*	5 calendar days	
- *Final Repair*	30 calendar days	
- *Resurvey*	Included in final repair	
- *DOR Deadline*	"Difficult to repair" components must be repaired by the end of the consent decree term (two years) or during next scheduled shutdown or well shut-in, whichever is sooner	
- *Additional DOR Info*	Must notify North Dakota Department of Public Health	

The consent decree required the completion of initial monitoring by the end of 2016 at well sites, with monthly AVO and semiannual OGI inspections occurring thereafter. Low-production wells are excluded from these regular monitoring requirements, where low production is defined as producing less than 15 barrels (bbl) per day. Operators must attempt leak repairs within 5 days of detection, and repairs must be completed within 30 days, with a resurvey required upon completing the repair. If components are difficult to repair, the operator may repair them by the end of the consent decree term (2 years) or during the next schedule shutdown or well shut-in, whichever is sooner. Records of each monitoring survey, when each survey took place, equipment inspected, leaks found, and the repair fate of the leaks, including DOR, are also required. Based on discussions with state regulators, approximately 9,000 wells are subject to this consent decree.[23]

Table 14 provides a summary of the criteria evaluated for equivalency and determination of equivalency of North Dakota's fugitive emissions requirements to the 2018 Proposal. However, we are not determining these requirements to be equivalent because by their nature, consent decrees are negotiated terms for non-compliance and contain an expiration date, after which sources return to compliance with the underlying regulatory provisions, permit terms, etc. Further, inclusion of settlement terms from a consent decree as an alternative standard would essentially endorse regulation through enforcement as a pathway to the establishment of

[23] Conversation with Jim Semerad, North Dakota Department of Health. September 11, 2017.

alternative standards. For these reasons, the EPA believes that evaluation of settlement agreement terms reached through negotiated resolution to an enforcement action would be an inappropriate basis from which to determine equivalency for regulations promulgated through notice and comment rulemaking.

Table 14. Equivalency of North Dakota's Fugitive Emissions Requirements to 2018 Proposal

Regulation	N.D.A.C. § 33-15-07-02(1), enforced by Consent Decrees
Effective Date	October 17, 2016
Monitoring Instrument	OGI
Leak Definition	Yes
Initial Monitoring	
- *Well Sites*	Yes
- *Compressor Stations*	
Monitoring Frequency	
- *Well Sites*	Yes
- *Low Production Wells*	No
- *Compressor Stations*	
Repair	
- *First Attempt*	Yes
- *Final Repair*	
- *Resurvey*	
- *DOR Deadline*	

5.8 Ohio

On April 4, 2014, the Ohio EPA approved general permits 12.1 and 12.2 for well sites with small and large flares, respectively, that have conducted high-volume horizontal hydraulic fracturing.[24] These permits only apply to well sites that emit less than 1 tpy of any hazardous air pollutant (HAP), excluding those subject to 40 CFR Part 63, Subpart HH.[25] The fugitive emissions requirements in these permits are referred to as leak detection and repair (LDAR), and are the same for both permits. Ohio also approved general permit 18.1 for equipment leaks at natural gas compressor stations on February 7, 2017.[26] This permit applies to facilities that have the potential to emit 10.56 tpy of VOC or greater from fugitive equipment leaks. A summary of Ohio's fugitive emissions requirements is provided in Table 15.

[24] Ohio well site permits available at http://epa.ohio.gov/dapc/genpermit/oilandgaswellsiteproduction.aspx
[25] National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities
[26] Available at http://epa.ohio.gov/dapc/genpermit/ngcs/GP_181.aspx

Table 15. Summary of Fugitive Emissions Requirements in Ohio

Permit	General Permits 12.1 and 12.2		General Permit 18.1	
Effective Date	April 14, 2014		February 7, 2017	
Monitoring Instrument	OGI	Method 21	OGI	Method 21
Leak Definition	Visible leak	500 or 10,000 ppm	Visible leak	500, 2,000, or 10,000 ppm[a27]
Initial Monitoring				
- *Well Sites*	90 days		NA	
- *Compressor Stations*	NA		60 days	
Monitoring Frequency				
- *Well Sites*	Quarterly for 1 year, then semiannual or annual (based on 2% leak rate)		NA	
- *Low Production Wells*				
- *Compressor Stations*	NA		Quarterly	
Repair				
- *First Attempt*	5 calendar days		As soon as practicable	
- *Final Repair*	30 calendar days		30 calendar days	
- *Resurvey*	Within repair timeframe		Within repair timeframe	
- *DOR Deadline*	40 CFR § 60.5416(c)(5)		40 CFR § 60.5397a(h)(2)	
- *Additional DOR Info*	NA		NA	

[a] When using Method 21, leak definitions vary depending on component: for compressors and closed vent systems (CVS), the leak definition is 500 ppm, and for all other equipment, the leak definition is 10,000 ppm.

Each permittee for well sites is required to develop and implement an LDAR program for ancillary equipment that requires monitoring using OGI or Method 21. The permits do not appear to allow for alternative instrument monitoring methods. Initial monitoring is required within 90 days of startup followed by quarterly monitoring for a period of 1 year. After the first year, if less than 2% of components are found to be leaking, then the monitoring frequency is reduced to semiannual. If less than 2% of components are found to be leaking after two semiannual inspections, then the monitoring frequency can be reduced to annual. However, if the percent of components leaking during any subsequent monitoring events is equal to or greater than 2%, the monitoring frequency is reset to quarterly for a 1-year period before less frequent monitoring can be utilized.. When using OGI, leaks are defined as visible emissions. When using Method 21, leak definitions vary depending on component: for compressors and closed vent systems (CVS), the leak definition is 500 ppm, and for all other equipment, the leak definition is 10,000 ppm. Open-ended lines (OEL) must be equipped with a cap, blind flange, plug, or a second valve. Permittees must make a first attempt at repair within 5 days of detection of a leak, and the repair must be completed within 30 days after detection. If leaks cannot be repaired

[27] When using Method 21, leak definitions vary depending on component: for compressors and closed vent systems (CVS), the leak definition is 500 ppm, and for all other equipment, the leak definition is 10,000 ppm.

within that time frame, the general permit references the DOR provisions allowed under the 2012 NSPS OOOO, which require completion of delayed repairs at the end of the next shutdown.[28]

The requirements for compressor stations are similar to those for well sites, with a few exceptions. Initial monitoring must be completed by June 3, 2017 or within 60 days of startup, with subsequent monitoring on a quarterly basis. Intermittent/snap-acting pneumatic controllers are included in the list of ancillary equipment, and a separate leak definition of 2,000 ppm is provided for pumps. The permit requires operators to begin repairs as soon as practicable upon detection, with completion of repairs within 30 days. If leaks cannot be repaired within that time frame, the general permit references the DOR provisions allowed under the 2016 NSPS OOOOa. The permit also requires weekly AVO inspections when operators are present at a facility and the facility is operating.

Table 16 provides a summary of the criteria evaluated for equivalency and our determination of equivalency of Ohio's fugitive emissions requirements to the 2018 Proposal.

Table 16. Equivalency of Ohio's Fugitive Emissions Requirements to 2018 Proposal

Permit	General Permits 12.1 and 12.2		General Permit 18.1	
Effective Date	April 14, 2014		February 7, 2017	
Monitoring Instrument	OGI	Method 21	OGI	Method 21
Leak Definition	Yes	500 ppm – Yes	Yes	500 ppm - Yes
Initial Monitoring				
- *Well Sites*	No		NA	
- *Compressor Stations*	NA		Yes	
Monitoring Frequency				
- *Well Sites*	Yes		NA	
- *Low Production Wells*				
- *Compressor Stations*	NA		Yes	
Repair				
- *First Attempt*	Yes		Yes	
- *Final Repair*				
- *Resurvey*				
- *DOR Deadline*	No[29]			

[28] The specific requirements in the 2012 NSPS OOOO (at 40 CFR 60.5416(c)(5)) are limited to emissions detected on closed vent systems associated with storage vessels, however, it is our understanding that Ohio applies these same requirements for all affected components under the permit program.
[29] GPs 12.1 and 12.2 refer to DOR provisions in the 2012 NSPS OOOO.

5.9 Oklahoma

The Oklahoma Administrative Code (OAC) prohibits leakage from wellhead connections, surface equipment, and tank batteries (OAC 165:10-3-12), as well as any other gaseous waste at well sites (OAC 165:10-3-14). In addition, OAC 252:100-7-60.5(a)(2)(A) requires that minor sources comply with the 2016 NSPS OOOOa.[30] We are not evaluating equivalency of the permit requirements for Oklahoma because the current requirements incorporate the 2016 NSPS OOOOa.

5.10 Pennsylvania

5.10.1 General Permits 5 and 5A

On June 7, 2018, the Pennsylvania Department of Environmental Protection (PADEP) finalized General Permits 5 and 5A[31] for compressor stations and unconventional well sites, respectively, with an effective date of August 8, 2018. A summary of the fugitive emissions requirements within each permit is provided in Table 17.

Table 17. Summary of Permit Fugitive Emissions Requirements in Pennsylvania

Permit	General Permit 5			General Permit 5A		
Effective Date	August 8, 2018			August 8, 2018		
Monitoring Instrument	OGI	EPA Method 21	Other approved	OGI	EPA Method 21	Other approved
Leak Definition	Visible leak	500 ppm	State-defined	Visible leak	500 ppm	State-defined
Initial Monitoring						
- *Well Sites*	NA			60 days		
- *Compressor Stations*	60 days			NA		
Monitoring Frequency						
- *Well Sites*	NA			Quarterly (unconventional wells)		
- *Low Production Wells*						
- *Compressor Stations*	Quarterly			NA		
Repair						
- *First Attempt*	5 days			5 days		
- *Final Repair*	15 days			15 days		
- *Resurvey*	30 days			30 days		
- *DOR Deadline*	Next blowdown, with final repair within 2 years			Next blowdown, with final repair within 2 years		
- *Additional DOR Info*	If parts are ordered, repair within 10 days or receipt			If parts are ordered, repair within 10 days or receipt		

[30] Oklahoma regulations available at: www.oar.state.ok.us/.
[31] Pennsylvania's General Permits 5 and 5A available at http://www.dep.pa.gov/Business/Air/BAQ/Permits/Pages/GeneralPermits.aspx

The requirements for the two permits are the same. Monitoring must begin within 60 days of startup, and follow a quarterly instrument monitoring schedule. Operators must use OGI, Method 21 at 500 ppm, or other approved device to detect gaseous hydrocarbon leaks. Operators must first attempt to repair leaks within 5 days of detection, with final repairs being made within 15 days. Components must be resurveyed within 30 days of the final repair. DOR provisions are included for situations where a shutdown is required or if parts are needed to make repairs. The general permits also require monthly AVO inspections.

Table 18 provides a summary of the criteria evaluated for equivalency and our determination of equivalency of Pennsylvania's permit fugitive emissions requirements to the 2018 Proposal.

Table 18. Equivalency of Pennsylvania's Permit Fugitive Emissions Requirements to 2018 Proposal

Permit	General Permit 5		General Permit 5A	
Effective Date	August 8, 2018		August 8, 2018	
Monitoring Instrument	OGI	EPA Method 21	OGI	EPA Method 21
Leak Definition	Yes	Yes	Yes	Yes
Initial Monitoring				
- *Well Sites*	NA		Yes	
- *Compressor Stations*	Yes		NA	
Monitoring Frequency				
- *Well Sites*	NA		Yes	
- *Low Production Wells*				
- *Compressor Stations*	Yes		NA	
Repair				
- *First Attempt*	Yes		Yes	
- *Final Repair*				
- *Resurvey*				
- *DOR Deadline*	Other state-approved monitoring instruments		Other state-approved monitoring instruments	

5.10.2 Exemption No. 38

Exemption No. 38 of the Air Quality Permit Exemption List applies to unconventional well sites.[32] The PADEP has also finalized updates to this exemption, but we did not identify any changes from the current fugitive requirements.[33] Components included in the exemption's fugitive emissions requirements are connectors, flanges, storage vessels, valves, and compressor

[32] Exemption available at http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf.
[33] Proposed exemption available at http://www.dep.pa.gov/business/air/pages/methane-reduction-strategy.aspx.

seals in natural gas or hydrocarbon liquids service. The exemption requires monitoring within 60 days of startup and annually thereafter. Monitoring may be conducted using OGI, gas leak detectors, or other state approved methods. Leaks are defined as "no detectable emissions"[34] if using Method 21, 500 ppm if using a gas leak detector, and visible leaks if using OGI. All leaks must be repaired within 15 days of finding the leak. The exemption also includes DOR provisions for when a shutdown is necessary or if parts are needed. However, we were unable to determine any specific requirements related to when delayed repairs must be completed from the information available at the time of our analysis.

We have not determined whether the requirements in Exemption No. 38 are equivalent to those in the 2018 Proposal, though we are soliciting comment in the preamble on whether or not a state would revert back to its original program once the monitoring frequency for well sites is reduced. A summary of the requirements contained in the exemption is presented in Table 19.

[34] Defined as a local VOC concentration at the surface of a leak source, adjusted for local VOC ambient concentration, that is less than 2.5 percent of the specified leak definition concentration, that indicates that a VOC emission (leak) is not present.

Table 19. Summary of Fugitive Emissions Requirements in Pennsylvania's Exemption No. 38

Regulation	Exemption No. 38		
Effective Date	December 11, 2015		
Monitoring Instrument	OGI	Gas analyzer	Other approved
Leak Definition	Visible leak	500 ppm	State-defined
Initial Monitoring			
- *Well Sites*	60 days		
- *Compressor Stations*	NA		
Monitoring Frequency			
- *Well Sites*	Annual (for unconventional wells)		
- *Low Production Wells*			
- *Compressor Stations*	NA		
Repair			
- *First Attempt*	NA		
- *Final Repair*	15 days		
- *Resurvey*	NA		
- *DOR Deadline*	Next shutdown		
- *Additional DOR Info*	DOR provision if parts are ordered, but no requirements on repair timeline		

~~***5.10.1 General Permit 5***~~

~~General Permit 5 (GP-5) is a General Plan Approval and/or General Operating Permit for midstream natural gas gathering, compression and/or processing facilities that are minor air contamination facilities.[35] The permit language was approved on January 16, 2015. A summary of the GP-5 fugitive emissions requirements is provided in Table 17.~~

~~[35] Pennsylvania's current GP-5 available at http://www.dep.state.pa.us/dep/deputate/airwaste/aq/permits/gp/GP-5_2-25-2013.pdf~~

~~Table 17. Summary of Current Permit Fugitive Emissions Requirements in Pennsylvania~~

~~Permit~~	~~General Permit 5~~	
~~Effective Date~~	~~January 16, 2015~~	
~~Monitoring Instrument~~	~~OGI~~	~~Other approved~~
~~Leak Definition~~	~~Visible leak~~	~~State-defined~~
~~Initial Monitoring~~		
~~- *Well Sites*~~	~~NA~~	
~~- *Compressor Stations*~~	~~180 days~~	
~~Monitoring Frequency~~		
~~- *Well Sites*~~	~~NA~~	
~~- *Low Production Wells*~~		
~~- *Compressor Stations*~~	~~Quarterly~~	
~~Repair~~		
~~- *First Attempt*~~	~~As soon as practicable~~	
~~- *Final Repair*~~	~~15 calendar days~~	
~~- *Resurvey*~~	~~Within repair timeframe~~	
~~- *DOR Deadline*~~	~~No~~	
~~- *Additional DOR Info*~~		

~~Monitoring must begin within 180 days of startup, and follow a quarterly instrument monitoring schedule. Operators must use OGI or other approved device to detect gaseous hydrocarbon leaks. All leaks at compressor stations or processing facilities must be repaired within 15 days of finding the leak. The general permit also requires monthly AVO inspections. There were no DOR provisions observed in GP-5.~~

~~Table 18 provides a summary of the criteria evaluated for equivalency and our determination of equivalency of Pennsylvania's fugitive emissions requirements to the 2018 Proposal.~~

~~Table 18. Equivalency of Pennsylvania's Fugitive Emissions Requirements to 2018 Proposal~~

~~Permit~~	~~General Permit 5~~
~~Effective Date~~	~~January 16, 2015~~
~~Monitoring Instrument~~	~~OGI~~
~~Leak Definition~~	~~Yes~~
~~Initial Monitoring~~	
~~- *Well Sites*~~	~~NA~~
~~- *Compressor Stations*~~	~~No~~
~~Monitoring Frequency~~	
~~– *Well Sites*~~	~~NA~~
~~– *Low Production Wells*~~	
~~– *Compressor Stations*~~	~~Yes~~
~~Repair~~	
~~– *First Attempt*~~	~~Yes~~
~~– *Final Repair*~~	
~~– *Resurvey*~~	~~Yes~~
~~– *DOR Deadline*~~	~~No~~

~~*5.10.2 Exemption No. 38*~~

~~Exemption No. 38 of the Air Quality Permit Exemption List applies to unconventional well sites.[36] The PADEP has proposed to update this exemption, but we did not identify any changes from the current fugitive requirements.[37] Components included in the exemption's fugitive emissions requirements are connectors, flanges, storage vessels, valves, and compressor seals in natural gas or hydrocarbon liquids service. The exemption requires monitoring within 60 days of startup and annually thereafter. Monitoring may be conducted using OGI, gas leak detectors, or other state approved methods. Leaks are defined as "no detectable emissions"[38] if using Method 21, 500 ppm if using a gas leak detector, and visible leaks if using OGI. All leaks must be repaired within 15 days of finding the leak. The exemption also includes DOR provisions for when a shutdown is necessary or if parts are needed. However, we were unable to determine any specific requirements related to when delayed repairs must be completed from the information available at the time of our analysis.~~

~~We have not determined whether the requirements in Exemption No. 38 are equivalent to those in the 2018 Proposal, though we are soliciting comment in the preamble on whether or not~~

~~[36] Exemption available at http://www.elibrary.dep.state.pa.us/dsweb/Get/Document-96215/275-2101-003.pdf.~~
~~[37] Proposed exemption available at http://www.dep.pa.gov/business/air/pages/methane-reduction-strategy.aspx.~~
~~[38] Defined as a local VOC concentration at the surface of a leak source, adjusted for local VOC ambient concentration, that is less than 2.5 percent of the specified leak definition concentration, that indicates that a VOC emission (leak) is not present.~~

~~a state would revert back to its original program once the monitoring frequency for well sites is reduced. A summary of the requirements contained in the exemption is presented in Table 19.~~

~~Table 19. Summary of Fugitive Emissions Requirements in Pennsylvania's Exemption No. 38~~

~~Regulation~~	~~Exemption No. 38~~		
~~Effective Date~~	~~December 11, 2015~~		
~~Monitoring Instrument~~	~~OGI~~	~~Gas analyzer~~	~~Other approved~~
~~Leak Definition~~	~~Visible leak~~	~~500 ppm~~	~~State-defined~~
~~Initial Monitoring~~			
~~- *Well Sites*~~	~~60 days~~		
~~- *Compressor Stations*~~	~~NA~~		
~~Monitoring Frequency~~			
~~- *Well Sites*~~	~~Annual (for unconventional wells)~~		
~~- *Low Production Wells*~~			
~~- *Compressor Stations*~~	~~NA~~		
~~Repair~~			
~~- *First Attempt*~~	~~NA~~		
~~- *Final Repair*~~	~~15 days~~		
~~- *Resurvey*~~	~~NA~~		
~~- *DOR Deadline*~~	~~Next shutdown~~		
~~- *Additional DOR Info*~~	~~DOR provision if parts are ordered, but no requirements on repair timeline~~		

5.11 Texas

There are three sets of fugitive emissions requirements that may apply to well sites in Texas: the Permit by Rule (PBR) requirements and two Standard Permit requirements. The PBR requirements may be applied to well sites that emit less than 25 tpy of VOC, while those that emit higher amounts may be required to follow the Standard Permit requirements. The PBR requirements are found within the Texas Administrative Code (TAC),[39] and the Standard Permits can be found within either the TAC[40] or the "Air Quality Standard Permit for Oil and

[39] 30 TAC § 106.352(e)(6); available at https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=106&rl=352.

[40] 30 TAC § 106.620; available at https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=R&app=9&p_dir=&p_rloc=&p_tloc=&p_ploc=&pg=1&p_tac=&ti=30&pt=1&ch=116&rl=620

Gas Handling and Production Facilities".[41] A summary of the fugitive emissions requirements in Texas are presented in Table 20.

Table 20. Summary of Fugitive Emissions Requirements in Texas

Regulation/Permit	30 TAC § 106.352(e)(6)	Standard Permit	30 TAC § 106.620
Effective Date	February 27, 2011	November 8, 2012	September 4, 2000
Monitoring Instrument	(Not specified)	Method 21	Gas Analyzer
Leak Definition	NA	500 or 10,000 ppm	500, 2,000, or 10,000 ppm
Initial Monitoring			
- *Well Sites*	90 days	90 days	90 days
- *Compressor Stations*			
Monitoring Frequency			
- *Well Sites*	Quarterly, with potential to reduce to annual if % leaking valves is low	Quarterly, with potential to reduce to annual if % leaking valves is low	Quarterly, with potential to reduce to annual if % leaking valves is low
- *Low Production Wells*			
- *Compressor Stations*	NA	NA	NA
Repair			
- *First Attempt*	NA	5 days	NA
- *Final Repair*	30 - 60 days	15 days	15 days
- *Resurvey*	15 days	NA	NA
- *DOR Deadline*	Next shutdown	Next shutdown	Next scheduled shutdown
- *Additional DOR Info*	If repair would create more emissions, repair during next shutdown	If repair would create more emissions, repair during next shutdown	NA

The PBR and Standard Permit fugitive requirements apply to connectors, flanges, OEL, PRD, thief hatches, valves, and agitator, compressor, and pump seals. The PBR does not specify a monitoring instrument for conducting fugitive emissions monitoring while the standard permit requires Method 21 (or a gas analyzer in the TAC version). For the standard permit, if site-wide emissions are less than 25 tpy VOC, then the leak definition is 10,000 ppm. If site-wide emissions are greater than or equal to 25 tpy VOC, then the leak definition is 500 ppm. In the TAC version of the standard permit, the leak definition varies based on the component, the site-wide emissions, and the facility's proximity to an off-plant receptor (e.g., a residential area). Texas does not require separate initial monitoring for fugitive emissions, though regular

[41] Texas "Air Quality Standard Permit for Oil and Gas Handling and Production Facilities" available at https://www.tceq.texas.gov/assets/public/permitting/air/Announcements/oilgas-sp.pdf.

quarterly instrument monitoring is required. The PBR and Standard Permit also allow for well sites to reduce their monitoring frequency to annual if the percentage of leaking valves at the site is low. If a leak is detected, operators must begin repair of the leak within 5 days if operating under the Standard Permit, and the timeline for repair completion can range from 15 to 60 days depending on the specific requirements for the site. DOR provisions are included for when a shutdown or blowdown is necessary. In these situations, operators are required to complete the repair during the next scheduled shutdown.

Table 21 provides a summary of the criteria evaluated for equivalency and our determination of equivalency of Texas's fugitive emissions requirements to the 2018 Proposal. It is difficult to draw a conclusion of equivalency for the PBR because that program does not specify a monitoring instrument.

Table 21. Equivalency of Texas Fugitive Emissions Requirements to 2018 Proposal

Regulation/Permit	30 TAC § 106.352(e)(6)	Standard Permit	30 TAC § 106.620
Effective Date	February 27, 2011	November 8, 2012	September 4, 2000
Monitoring Instrument	(Not specified)	Method 21	Gas Analyzer
Leak Definition	No	500 ppm - Yes	2,000 ppm - Yes[42]
Initial Monitoring			
- *Well Sites*	No	No	No
- *Compressor Stations*	NA	NA	NA
Monitoring Frequency			
- *Well Sites*	Yes	Yes	Yes
- *Low Production Wells*			
- *Compressor Stations*	NA	NA	NA
Repair			
- *First Attempt*	Yes	Yes	Yes
- *Final Repair*			
- *Resurvey*	No	No	No
- *DOR Deadline*	Yes	Yes	Yes

5.12 Utah

The Utah Department of Environmental Quality (UDEQ) approved a "General Approval Order for a Crude Oil and Natural Gas Well Site and/or Tank Battery" on June 5, 2014[43] and has

[42] If Method 21 is used as the instrument monitoring

[43] Utah General Approval Order available at http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf.

also finalized PBR fugitive emissions requirements for certain well sites within the Utah Administrative Code, with an effective date of March 2, 2018.[44] A summary of Utah's fugitive emissions requirements is provided in Table 22.

Table 22. Summary of Fugitive Emissions Requirements in Utah

Regulation	General Approval Order			Utah Admin. Code r. 307-509	
Effective Date	June 5, 2014			March 2, 2018	
Monitoring Instrument	OGI	Method 21	TDLAS	OGI	Method 21
Leak Definition	Visible leak	500 ppm	500 ppm	Visible leak	500 ppm
Initial Monitoring					
- *Well Sites*	90 days			60 days	
- *Compressor Stations*	NA			NA	
Monitoring Frequency					
- *Well Sites*	Annual if production ≥ 10,000 bbl/a; Quarterly if production ≥ 25,000 bbl/a and storage vessel present.			Semiannual if uncontrolled storage tank and dehydrators emissions > 4 tpy VOC	
- *Low Production Wells*					
- *Compressor Stations*	NA			NA	
Repair					
- *First Attempt*	5 days			NA	
- *Final Repair*	15 days			15 days	
- *Resurvey*				30 days	
- *DOR Deadline*	Next shutdown, with final repair within 6 months			Next shutdown or shut-in, after a vent blowdown, or within 2 years, whichever is earlier	
- *Additional DOR Info*	If parts are ordered, repair within 15 days of receipt			Unsafe to repair during operation of the unit	

The General Approval Order (GAO) requires LDAR for components (compressors, connectors, flanges, PRDs, valves, pumps, other vents, process drains, pump seals, compressor seals, access door seals, and other seals that contain or contact a process stream with hydrocarbons) based on the annual throughput of crude oil and condensate, as well as the equipment present at the site. Annual instrument monitoring is required for sources that have a throughput greater than or equal to 10,000 bbl and for sources that do not have a crude oil or condensate storage tank on site. Quarterly instrument monitoring is required for sources that have a throughput greater than or equal to 25,000 bbl. For sources subject to quarterly monitoring, provisions are available for reduced monitoring frequency if no leaks are found within a single year monitoring timeframe. Repairs must be made within 15 days of finding a leak. DOR is allowed if replacement parts are unavailable (parts must be ordered within 5 days of detection and repairs must be completed within 15 days after receipt of the parts) or technically infeasible to repair without a shutdown (shutdown must occur within 6 months of

[44] Utah Admin. Code r. 307-509. Final rule text available at https://www.utah.gov/pmn/files/359797.pdf#page=2

finding leak or operators must demonstrate emissions from shutdown would be greater than the uncontrolled leaking component). The monitoring can be performed using Method 21, a tunable diode laser absorption spectroscopy (TDLAS) or OGI. A leak is defined as a reading of 500 ppm with Method 21 or TDLAS, or a visible leak with OGI.

Operators had the option to comply with the requirements of the GAO, or they could have obtained a source-specific approval order (i.e., Utah's version of a permit) from UDEQ. No well sites have operated under this GAO, and the state is no longer accepting applications under the order. Of the source-specific approval orders that have been issued, all require at least annual monitoring. With UDEQ's PBR rules, well sites that are not major sources[45] will no longer be able to apply for source-specific approval orders and must comply with the PBR requirements. When complying with these requirements, well sites must also register with the state, as required by Utah Admin. Code r. 307-505. It should be noted that neither the GAO nor the PBR apply to compressor stations, which are covered by source-specific approval orders that differ in their requirements among sites.

The fugitive emissions requirements in the PBR only cover well sites where uncontrolled storage vessel and dehydrator emissions are greater than 4 tpy. The requirements cover most of the components included in the 2018 Proposal (except for storage vessels) and allow for OGI or Method 21 monitoring with a leak definition of 500 ppm. Monitoring must be conducted 60 days after startup and semiannually thereafter. Operators have 15 days to repair a leak after detection and must resurvey the components 30 days after the leak is repaired. DOR provisions are included if a shutdown or vent blowdown is needed to repair a leak or if it is unsafe to repair during operation of the unit. In these situations, operators have until the next shutdown or 2 years to repair the leak, whichever is earlier. Table 23 provides a summary of the criteria evaluated for equivalency and our preliminary evaluation of equivalency of Utah's fugitive emissions requirements to the 2018 Proposal. Since no operators have elected to comply with the GAO requirements and the opportunity to apply to do so has closed, we do not think it is appropriate to conclude the GAO is equivalent.

[45] As defined in Utah Admin. Code r. 307-101-2

Table 23. Equivalency of Utah's Fugitive Emissions Requirements to 2018 Proposal

Regulation	General Approval Order		Utah Admin. Code r. 307-509	
Effective Date	June 5, 2014		March 2, 2018	
Monitoring Instrument	OGI	Method 21	OGI	Method 21
Leak Definition	Yes	Yes	Yes	Yes
Initial Monitoring				
- *Well Sites*	No		Yes	
- *Compressor Stations*	NA		NA	
Monitoring Frequency				
- *Well Sites*	No (only applies to well sites with annual production > 10,000 bbl)		Yes (sites where uncontrolled storage tank and dehydrators emissions > 4 tpy VOC)	
- *Low Production Wells*				
- *Compressor Stations*	NA		NA	
Repair				
- *First Attempt*	Yes		Yes	
- *Final Repair*				
- *Resurvey*				
- *DOR Deadline*				

5.13 West Virginia

Permits issued for well sites and compressor stations in West Virginia require compliance with the fugitive emissions requirements in the 2016 NSPS OOOOa.[46] This requirement is found in section 12 of the Class II General Permit G70-D for well sites, and in section 16 of the Class II General Permit G35-D for compressor stations. Before the 2016 NSPS OOOOa, West Virginia had separate fugitive emissions requirements for well sites in sections 4.1.3 through 4.2 of the Class II General Permit G70-B. Those previous permits required quarterly monitoring with AVO, Method 21 (at a leak definition of 500 ppm), OGI, or a combination of the three and applied to valves, above-ground piping, and pumps. Operators were required to complete the repair within 15 days of finding a leak, with a first attempt made within 5 days. No resurvey requirements were included. DOR provisions were included for situations where a shutdown would be required to repair a leak or if emissions would be higher as a result of repairing the leak without the delay. For these situations, operators were required to repair the leak during the next shutdown.

We are not evaluating equivalency of the permit requirements for West Virginia because the current requirements incorporate the 2016 NSPS OOOOa.

5.14 Wyoming

The Wyoming Department of Environmental Quality (Wyoming DEQ) issued regulations in June 2015 for existing (as of January 1, 2014) PAD facilities (locations where more than one

[46] West Virginia permits available at http://dep.wv.gov/daq/permitting/Pages/airgeneralpermit.aspx.

well and/or associated production equipment are located, where some or all production equipment is shared by more than one well or where well streams from more than one well are routed through individual production trains at the same location), single-well oil and gas production facilities or sources, and all compressor stations that are located in the Upper Green River Basin (UGRB) ozone nonattainment area.[47] A summary of the Wyoming requirements is presented in Table 24.

Table 24. Summary of Fugitive Emissions Requirements in Wyoming

Regulation	020-002-008 Wyo. Code R. § 6(g)	
Effective Date	December 20, 2016	
Monitoring Instrument	OGI	Method 21
Leak Definition	State-defined	State-defined
Initial Monitoring		
- *Well Sites*	90 days	
- *Compressor Stations*		
Monitoring Frequency		
- *Well Sites*	Quarterly (UGRB with site-wide emissions ≥ 4 tpy VOC)	
- *Low Production Wells*		
- *Compressor Stations*		
Repair		
- *First Attempt*	NA	
- *Final Repair*		
- *Resurvey*		
- *DOR Deadline*		
- *Additional DOR Info*		

The Wyoming DEQ rule requires operators with fugitive emissions greater than or equal to 4 tpy of VOC to develop and implement an LDAR protocol. The deadline for development of this protocol was January 1, 2017. Operators are required to monitor components (flanges, connectors (other than flanges), OELs, pumps, valves, and "other" components listed in Table 2-4 of the EPA's Protocol for Equipment Leak Emissions Estimates) quarterly using a combination of Method 21, OGI, other instrument based technologies, or AVO inspections. No specific repair deadlines are included in the regulation. Table 25 provides a summary of the criteria evaluated for equivalency and determination of equivalency of Wyoming's fugitive emissions requirements to the 2018 Proposal. However, due to the flexibility of the requirements, we are unable to include alternative fugitive standards relative to these requirements.

[47] Wyoming regulations are available at https://rules.wyo.gov/.

Table 25. Equivalency of Wyoming's Fugitive Emissions Requirements to 2018 Proposal

Regulation	020-002-008 Wyo. Code R. § 6(g)	
Effective Date	December 20, 2016	
Monitoring Instrument	OGI	Method 21
Leak Definition	Yes	No
Initial Monitoring		
- *Well Sites*	No	
- *Compressor Stations*		
Monitoring Frequency		
- *Well Sites*	Yes (for UGRB with site-wide emissions > 4 tpy VOC)	
- *Low Production Wells*		
- *Compressor Stations*		
Repair		
- *First Attempt*	No	
- *Final Repair*		
- *Resurvey*		
- *DOR Deadline*		

6.0 CONCLUSIONS

Based on the analysis presented in section 5.0, we are proposing that fugitive emissions requirements related to monitoring, repair, and recordkeeping are equivalent to the 2018 Proposal for the following state programs:

- California Code of Regulations, title 17, §§95665-95667, effective January 1, 2020;
- Colorado Regulation 7, §§XII.L, effective June 30, 2018, or XVII.F, effective October 15, 2014 for well sites and January 1, 2015 for compressor stations;
- Ohio General Permits 12.1 and 12.2, effective April 14, 2014;
- Ohio General Permit 18.1, effective February 7, 2017;
- Pennsylvania General Permit 5, effective January 16, 2015;
- Texas Air Quality Standard Permit for Oil and Gas Handling and Production Facilities, effective November 8, 2012, or at 30 Texas Administrative Code §116.620, effective September 4, 2000; and
- Utah Administrative Code R307-509, effective March 2, 2018.

For reasons stated in section 5.0 and summarized here, we are unable to determine equivalency of the fugitive emissions requirements for the following state programs:

- Administrative Rules of Montana Title 17, Chapter 8, Subchapters 16 and 17 because instrument monitoring is not required.
- New Mexico Administrative Code Title 19, Chapter 15, Part 2 because we were unable to determine the enforcement mechanism.

- North Dakota Administrative Code Chapter 33-15-07 because of the temporary nature of the Consent Decrees used to enforce these requirements.
- Wyoming Administrative Rules Reference No. 020.0002.8.12202016 because of the flexibility of the requirements.

Finally, the following states either incorporate the fugitive emissions requirements in the 2016 NSPS OOOOa or do not have requirements that we were able to evaluate:

- Alaska
- Oklahoma
- West Virginia

Spreadsheet Descriptions
Gas Well Pad MP
Oil Well Pad MP
Oil_Gas Well Pad MP
LP Gas Well Pad MP
LP Oil Well Pad MP
LP Oil_Gas Well Pad MP
MP Method 21 Cost
Well - 10,000
Well - 500
HP Model Plant 2015-10,000
HP Model Plant 2015-500
LP Model Plant 2015-10,000
LP Model Plant 2015-500
Composition and Factors
Emissions (Production)
Oil well equipment counts obtained from Table W-1C of 40 CFR Part 98, Subpart W.
Gas well equipment and component counts based on total quantity of equipment for both Eastern & Western U.S. from the EPA/GRI Methane Emissions from the Natural Gas
Oil and Gas production TOC emission factors obtained from Table 2-4 from the EPA Equipment Leaks Protocol for components in gas service.
Model plant emissions for both oil and gas well pads based on 2 production wells per well site.
Method 21 Cost Assumptions (Production)
Labor rates obtained from Table 11 in the Memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, Analysis of Emission Reductions Techniques for Equipment Leaks, Decemb
Hours to read rule, develop monitoring plan and planning obtained from Attachment 7 in the Memorandum from Ken Meardon, PES to John Schaefer, EPA, Equipment Leak Ar
For production wells, the assumption of 22 well sites per natural gas production company was derived from the City of Fort Worth Natural Gas Air Quality Study, July 2011.
The leak percentage (1.18%) was obtained from Table 5 for baseline gas valves from the memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, Analysis of Emission Reduct
The repair costs were estimated assuming 1.18% of the total components were found leaking per survey. 75% were assumed to be repaired online using 0.17 hours per repair
The component resurvey cost based on estimates of resurvey costs assuming 5 minutes per leak at $57.80 per hour, adjusted to 2016$.

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Spreadsheet calculation of the model plant for natural gas production well pads. Includes calculations for equipment and component counts for a 2-well model plant.
Spreadsheet calculation of the model plant for oil production well pads. Includes calculations for equipment and component counts for a 2-well model plant.
Spreadsheet calculation of the model plant for oil production well pads (GOR>300). Includes calculations for equipment and component counts for a 2-well model plant.
Spreadsheet calculation of the model plant for low production gas well pads (<15 barrels of oil equivalent per day). Includes calculations for equipment and component counts
Spreadsheet calculation of the model plant for low production oil well pads (<15 barrels of oil equivalent per day). Includes calculations for equipment and component counts
Spreadsheet calculation of the model plant for oil w/associated gas low production well pad (<15 barrels of oil equivalent per day). Includes calculations for equipment and con
Cost calculations for developing and implementing equipment leak monitoring program at a well site.
Emission and cost per ton calculation summary for a 10,000 ppm Method 21 monitoring program at natural gas and oil production well pad model plants.
Emission and cost per ton calculation summary for a 500 ppm Method 21 monitoring program at natural gas and oil production well pad model plants.
Spreadsheet calculation of the model plant for high production well site (10,000 ppm leak detection).
Spreadsheet calculation of the model plant for high production well site (500 ppm leak detection).
Spreadsheet calculation of the model plant for low production well site (10,000 ppm leak detection).
Spreadsheet calculation of the model plant for low production well site (500 ppm leak detection).
Natural gas composition values used to calculate methane, VOC and HAP emissions.
8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h).
neral and operations managers ($57.80/hr) and leak repair and labor charge ($66.24/hr), adjusted to 2016$.
nd Phenolic Resins NESHAP.
or Equipment Leaks, December 21, 2011.
sted to 2016$. 25% were assumed to be repaired offline using 4.0 hours per repair at $66.24/hr, adjusted to 2016$.

Model Plant for Gas Well Pad

Equipment	*Model Plant (GRI)* [1]	*Rounded Model Plant (GRI)* [1]	*Updated GHGI Counts* [2]	*Rounded GHGI Counts*
Gas Wellheads	2.00	2.0	2.00	2.0
Seperators	1.56	2.0	1.37	2.0
Meter/Piping	0.83	1.0	1.71	2.0
In-Line Heaters	0.82	1.0	0.41	1.0
Dehydrators	0.55	1.0	0.05	1.0

[1] Estimated by rounding up the average equipment count per gas well from the EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

[2] Based on 2015 GHGI equipment counts for gas wells

Component Counts for Model Plant Equipment for Gas Well Pad

Components	*Model Plant (GRI)* [1]	*Rounded Model Plant (GRI)* [1]	*Updated GHGI Counts*	*Rounded GHGI Counts*
Valves	89	114	78	127
Connectors	324	414	282	462
Open-Ended Lines	11	14	9	14
Pressure Relief Valves	5	6	4	7

[1] Estimated using GRI model plant equipment count and average components per equipment

Estimated Component Counts per Equipment at Natural Gas Production Sites

	Average Component Count per Equipment[1]				Average Component Count per Model Plant			
Equipment	**Valves**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Valves**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**
Gas Wellheads	9.5	37.0	0.7	0.0	18.9	74.0	1.5	0.0
Separators	21.6	68.5	3.7	1.2	43.2	136.9	7.5	2.5
Meters/Piping	12.9	47.8	0.5	0.5	25.9	95.6	0.9	0.9
Gathering Compressors	71.1	175.1	2.9	3.9				
In-Line Heaters	14.0	65.0	2.0	1.0	14.0	65.0	2.0	1.0
Dehydrators	24.0	90.0	2.0	2.0	24.0	90.0	2.0	2.0

[1] Calculated by summing the total quantity of equipment and dividing by the total number of sites for both Eastern & Western U.S.
EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

GRI Equipment Counts

Equipment	**Eastern US**	**Western US**	**Average**	**Avg/Well**	**GHGI**
Gas Wells	192	184	188	----	----
Heaters	77	77	77	0.41	0.21
Separators	110	183	147	0.78	0.69
Dehydrators	52	52	52	0.28	0.03
Meters/Piping	83	73	78	0.41	0.86

[1] Equipment counts obtained from EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7
3.5 Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems

Model Plant for Oil Well Pad

Equipment	*GHGI Average Equipment per Well*[1]	*Updated GHGI Counts*	*Rounded GHGI Counts*
Oil Wellheads		2.00	2.0
Seperators	0.36	0.72	1.0
Headers	0.18	0.36	1.0
Heater/Treaters	0.23	0.47	1.0

[1] Based on 2015 GHGI equipment counts for light crude production.

Component Counts for Model Plant Equipment for Oil Well Pad

Components	*Updated GHGI Counts*	*Rounded GHGI Counts*
Valves	20	29
Flanges	38	54
Connectors	26	42
Open-Ended Lines	0	0
Pressure Relief Valves	2	2

[1] Based on GHG equipment counts and component counts from Table W-1C of 40 CFR Part 98, Subpart W.

Estimated Component Counts per Equipment at Oil & Gas Production Sites

	Average Component Count per Equipment[1]					Average Component Count per Model Plant				
Equipment	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**
Wellheads	5	10	4	0	1	10.0	20.0	8.0	0.0	2.0
Seperators	6	12	10	0	0	6.0	12.0	10.0	0.0	0.0
Headers	5	10	4	0	0	5.0	10.0	4.0	0.0	0.0
Heater/Treaters	8	12	20	0	0	8.0	12.0	20.0	0.0	0.0

[1] Component counts obtained from Table W-1C of 40 CFR Part 98, Subpart W.

Model Plant for Oil w/ Associated Gas Well Pad

Equipment	*GHGI Average Equipment per Well*	*GHGI Equipment Counts*	*Rounded GHGI Equipment Counts*
Wellheads		2.00	2
Seperators (Light Crude)	0.36	0.72	1
Headers (Light Crude)	0.18	0.36	1
Heater/Treaters (Light Crude)	0.23	0.47	1
Meters/Piping (Natural Gas)	0.62	1.23	2

[1] Based on 2015 GHGI equipment counts for light crude production and meters/piping for natural gas.

Component Counts for Model Plant Equipment for Oil w/ Associated Gas Well Pad

Components	*Rounded Model Plant (GHG)* [1]
Valves	55
Flanges	54
Connectors	138
Open-Ended Lines	1
Pressure Relief Valves	3

[1] Estimated using GHG model plant equipment count and GHGI/GRI average components per equipment

Estimated Component Counts per Equipment at Oil & Gas Production Sites

Equipment	Average Component Count per Equipment[1]				
	Valves	Flanges	Connectors & Flanges	Open-Ended Lines	Pressure Relief Valves
Wellheads	5	10	4	0	1
Seperators	6	12	10	0	0
Headers	5	10	4	0	0
Heater/Treaters	8	12	20	0	0

[1] Component counts obtained from Table W-1C of 40 CFR Part 98, Subpart W.

Estimated Component Counts per Equipment at Natural Gas Production Sites

Equipment	Average Component Count per Equipment[1]				Average Component Count per Model Plant				
	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Flanges[3]
Gas Wellheads[2]	9.5	37.0	0.7	0.0	10.0	8.0	0.0	2.0	20.0
Separators[2]	21.6	68.5	3.7	1.2	6.0	10.0	0.0	0.0	12.0
Meters/Piping	12.9	47.8	0.5	0.5	25.9	95.6	0.9	0.9	
Heaters/Treaters[2]					8.0	20.0	0.0	0.0	12.0
Headers[2]					5.0	4.0	0.0	0.0	10.0
Gathering Compressors	71.1	175.1	2.9	3.9					
In-Line Heaters	14.0	65.0	2.0	1.0					
Dehydrators	24.0	90.0	2.0	2.0					

[1] Calculated by summing the total quantity of equipment and dividing by the total number of sites for both Eastern & Western U.S.
EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

[2] Component counts in average component count per model plant is from Table W-1C of 40 CFR Part 98, Subpart W.

[3] Average component counts for flanges used in average component count per model plant is from Table W-1C of 40 CFR Part 98, Subpart W.

Model Plant for Low Production Gas Well Pad

Equipment	*FW Study Counts* [1]	*Rounded FW Counts* [2]
Gas Wellheads	1.64	2.0
Seperators	1.12	2.0
Meter/Piping	0.01	1.0
In-Line Heaters	0.00	0.0
Dehydrators	0.08	1.0

[1] Equipment counts obtained from the City of Fort Worth Natural Gas Air Quality Study, Final Report, Emissions Calculations Workbook, J

[2] Estimated by rounding up the average equipment count per low production gas well from the City of Fort Worth Natural Gas Air Quality

Component Counts for Model Plant Equipment for Gas Well Pad

Components	*Updated FW Study Counts*	*Rounded FW Study Counts*	Scaling Factor
Valves	42	100	**0.787**
Connectors	145	349	**0.755**
Open-Ended Lines	6	12	**0.857**
Pressure Relief Valves	2	5	**0.714**

[1] Estimated using equipment counts from the City of Fort Worth Natural Gas Air Quality Study, July 2011 and average components per eq

Estimated Component Counts per Equipment at Natural Gas Production Sites

	Average Component Count per Equipment[1]				Average Component Count per Model Plant			
Equipment	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves
Gas Wellheads	9.5	37.0	0.7	0.0	18.9	74.0	1.5	0.0
Separators	21.6	68.5	3.7	1.2	43.2	136.9	7.5	2.5
Meters/Piping	12.9	47.8	0.5	0.5	12.9	47.8	0.5	0.5
Gathering Compressors	71.1	175.1	2.9	3.9				
In-Line Heaters	14.0	65.0	2.0	1.0	0.0	0.0	0.0	0.0
Dehydrators	24.0	90.0	2.0	2.0	24.0	90.0	2.0	2.0

[1] Calculated by summing the total quantity of equipment and dividing by the total number of sites for both Eastern & Western U.S.
EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-08

GRI Equipment Counts

Equipment	Eastern US	Western US	Average	Avg/Well	GHGI
Gas Wells	192	184	188	----	----
Heaters	77	77	77	0.41	0.21
Separators	110	183	147	0.78	0.69
Dehydrators	52	52	52	0.28	0.03
Meters/Piping	83	73	78	0.41	0.86

[1] Equipment counts obtained from EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 an
3.5 Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems

Model Plant for Low Production Oil Well Pad

Equipment	*Average Equipment per Well* [1]	*Updated GHGI Counts*	*Rounded GHGI Counts*
Oil Wellheads		2.00	2.0
Seperators	0.36	0.72	1.0
Headers	0.18	0.36	1.0
Heater/Treaters	0.23	0.47	1.0

[1] Based on 2015 GHGI equipment counts for light crude production.

Component Counts for Model Plant Equipment for Oil Well Pad

Components	*Rounded Scaled*
Valves	23
Flanges	41
Connectors	32
Open-Ended Lines	0
Pressure Relief Valves	2

[1] Based on GHG equipment counts and component counts from Table W-1C of 40 CFR Part 98, Subpart W.

Estimated Component Counts per Equipment at Oil & Gas Production Sites

	Average Component Count per Equipment[1]					Average Con	
Equipment	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Valve s**	**Flange s**
Wellheads	5	10	4	0	1	10.0	20.0
Seperators	6	12	10	0	0	6.0	12.0
Headers	5	10	4	0	0	5.0	10.0
Heater/Treaters	8	12	20	0	0	0.0	0.0

[1] Component counts obtained from Table W-1C of 40 CFR Part 98, Subpart W.

ponent Count per Model Plant		
Connectors	Open-Ended Lines	Pressure Relief Valves
8.0	0.0	2.0
10.0	0.0	0.0
4.0	0.0	0.0
0.0	0.0	0.0

Model Plant for Oil w/Associated Gas Low Production Well Pad

Equipment	*GHGI Average Equipment*	*GHGI Equipment Counts*	*Rounded GHGI Equipment*
Wellheads		2.00	2
Seperators (Light Crude)	0.36	0.72	1
Headers (Light Crude)	0.18	0.36	1
Heater/Treaters (Light Crude)	0.23	0.47	1
Meters/Piping (Natural Gas)	0.62	1.23	2

[1] Based on 2015 GHGI equipment counts for light crude production and meters/piping for natural gas.

Component Counts for Model Plant Equipment for Oil w/ Associated Gas Well Pad

Components	*Rounded Model Plant (GHG)* [1]
Valves	44
Flanges	41
Connectors	105
Open-Ended Lines	1
Pressure Relief Valves	3

[1] Estimated using GHG model plant equipment count and GHGI/GRI average components per equipment

Estimated Component Counts per Equipment at Oil & Gas Production Sites

	Average Component Count per Equipment[1]				
Equipment	**Valves**	**Flanges**	**Connectors & Flanges**	**Open-Ended Lines**	**Pressure Relief Valves**
Wellheads	5	10	4	0	1
Seperators	6	12	10	0	0
Headers	5	10	4	0	0
Heater/Treaters	8	12	20	0	0

[1] Component counts obtained from Table W-1C of 40 CFR Part 98, Subpart W.

Estimated Component Counts per Equipment at Natural Gas Production Sites

	Average Component Count per Equipment[1]				Average Component Count pe		
Equipment	**Valves**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Valves**	**Connectors**	**Open-Ended Lines**
Gas Wellheads[2]	9.5	37.0	0.7	0.0	8	6	0
Separators[2]	21.6	68.5	3.7	1.2	5	8	0
Meters/Piping	12.9	47.8	0.5	0.5	20	72	1
Heaters/Treaters[2]					6	15	0
Headers[2]					4	3	0

r Model Plant	
Pressure Relief Valves	Flanges[3]
1	15
0	9
1	
0	9
0	8

Gathering Compressors	71.1	175.1	2.9	3.9			
In-Line Heaters	14.0	65.0	2.0	1.0			
Dehydrators	24.0	90.0	2.0	2.0			

[1] Calculated by summing the total quantity of equipment and dividing by the total number of sites for both Eastern & Western U.S
EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/F

[2] Component counts in average component count per model plant is from Table W-1C of 40 CFR Part 98, Subpart W.

[3] Average component counts for flanges used in average component count per model plant is from Table W-1C of 40 CFR Part 98,

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Subpart W.

Cost Of Implementing Method 21 Monitoring Program at a Well Site

Item	Number of People	Number of Hours per Person	Total Hours	Labor Cost ($/hour)[a]	Biennial Method 21 ($/year)	Annual Method 21 ($/year)	Semia Meth ($/y
Company Level Costs							
Read rule and instructions	1	4	4	$61.21	$245	$245	
Development of Equipment Leaks Monitoring Plan	2.5	24	60	$61.21	$3,672	$3,672	$
Initial Activities Planning	2	8	16	$61.21	$490	$979	$
Notification of Initial Compliance Status	1	1	1	$61.21	$1,347	$1,347	$
M21 Monitoring and Data Collection System	N/A	N/A	N/A	N/A	25300	$25,300	$2
First Year Total Hours and Cost per Company			*102*		*$31,053*	*$31,543*	*$3*
First Year Total Hours and Cost per Well Site			*4.6*		*$1,412*	*$1,434*	*$*
Well Site Level Costs							
Subsequent Activities Planning	2	8	16	$61.21	$22	$45	
Method 21 Survey Cost	2	8	16	$61.21	$490	$979	$
Repair Cost	N/A	N/A	N/A	N/A	$158	$316	
M21 Resurvey Costs	N/A	N/A	N/A	N/A	$10	$20	
Travel to/from Well Pad	N/A	N/A	N/A	N/A			
Annual Report	1	4	4	$61.21	$245	$245	
Annual Hours and Cost per Well Site			*20*		*$925*	*$1,605*	*$*
Annual Cost with Amortized Capital Cost					*$1,161*	*$1,845*	*$*

[a] Labor rates obtained from Table 11 in the Memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, Analysis of Emission Reductions Techniques for Equipment Leaks, December 21, 2011 for general and operations managers ($57.80/hr) and leak repair and labor charge ($66.24/hr), adjusted to 2016$.

[b] Hours obtained from Attachment 7 in the Memorandum from Ken Meardon, PES to John Schaefer, EPA, Equipment Leak Analysis for Amino and Phenolic Resins NESHAP

[c] The 22 well sites per natural gas production company was derived from the City of Fort Worth Natural Gas Air Quality Study, July 2011.

[d] The leak percentage was obtained from Table 5 of Memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, Analysis of Emission Reductions Techniques for Equipment Leaks, December 21, 2011.

[e] The component resurvey cost based on the average subsequent monitoring fee in Table 13 of Memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, Analysis of Emission Reductions Techniques for Equipment Leaks, December 21, 2011.

[f] Cost values are adjusted for 2016$ using the GDP Deflator value os 1.058919 as updated by the Federal Reserve Economic Data on January 26, 2018.

1.058919 GDP Deflator

Average Model Plant Cost of Control for Well Pads w/o Recovery Credits - M21 Monitoring (10,000 ppm Leak Definition) - Single-pollutant

Model Plant	Total Capital Investment[1]	Annual LDAR Cost ($/yr)[2]	Recovery Credits ($/yr)[3]	Annual LDAR Cost w/o Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions (Tons/yr)	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions (Tons/yr)	VOC Cost Effectiveness ($/Ton)	HAP Emissions (Tons/yr)	HAP Emission Reductions (Tons/yr)	HAP Cost Effectiveness ($/Ton)
Model Plant													
Baseline - Gas Wells	-----	-----	-----	-----	5.91	-----	-----	1.643	-----	-----	0.0619	-----	-----
Stepped Monitoring	$1,445	$2,259		$2,259	3.23	2.68	$843	0.898	0.745	$3,031	0.0338	0.0281	$80,461
Semiannual Monitoring	$1,478	$3,213		$3,213	2.67	3.24	$992	0.743	0.901	$3,568	0.0280	0.0339	$94,710
Annual Monitoring	$1,434	$1,845		$1,845	3.42	2.49	$740	0.950	0.694	$2,661	0.0358	0.0261	$70,632
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	2.06	-----	-----	0.572	-----	-----	0.0215	-----	-----
Stepped Monitoring	$1,445	$2,259		$2,259	1.12	0.93	$2,423	0.312	0.259	$8,715	0.0118	0.0098	$231,329
Semiannual Monitoring	$1,478	$3,213		$3,213	0.93	1.13	$2,852	0.258	0.313	$10,259	0.0097	0.0118	$272,297
Annual Monitoring	$1,434	$1,845		$1,845	1.19	0.87	$2,127	0.330	0.241	$7,651	0.0124	0.0091	$203,070
Baseline - Oil Well (GOR > 300)	-----	-----	-----	-----	3.04	-----	-----	0.845	-----	-----	0.0318	-----	-----
Stepped Monitoring	$1,445	$2,259		$2,259	1.66	1.38	$1,638	0.462	0.383	$5,894	0.0174	0.0144	$156,454
Semiannual Monitoring	$1,478	$3,213		$3,213	1.37	1.67	$1,929	0.382	0.463	$6,938	0.0144	0.0174	$184,161
Annual Monitoring	$1,434	$1,845		$1,845	1.76	1.28	$1,438	0.489	0.357	$5,174	0.0184	0.0134	$137,341
Baseline - Low Production Gas Wells (<15 BOE)	-----	-----	-----	-----	4.80	-----	-----	1.335	-----	-----	0.0503	-----	-----
Stepped Monitoring	$1,445	$2,259		$2,259	2.62	2.18	$1,037	0.730	0.605	$3,731	0.0275	0.0228	$99,045
Semiannual Monitoring	$1,478	$3,213		$3,213	2.17	2.63	$1,221	0.603	0.732	$4,392	0.0227	0.0276	$116,586
Annual Monitoring	$1,434	$1,845		$1,845	2.78	2.03	$911	0.772	0.563	$3,276	0.0291	0.0212	$86,946
Biennial Monitoring	$1,412	$1,161		$1,161	3.36	1.44	$806	0.935	0.401	$2,900	0.0352	0.0151	$76,974
Baseline - Low Production Oil Well (GOR < 300)	-----	-----	-----	-----	1.83	-----	-----	0.508	-----	-----	0.0191	-----	-----
Stepped Monitoring	$1,445	$2,259		$2,259	1.00	0.83	$2,725	0.278	0.230	$9,802	0.0105	0.0087	$260,189
Semiannual Monitoring	$1,478	$3,213		$3,213	0.83	1.00	$3,207	0.230	0.279	$11,538	0.0087	0.0105	$306,268
Annual Monitoring	$1,434	$1,845		$1,845	1.06	0.77	$2,392	0.294	0.214	$8,605	0.0111	0.0081	$228,404
Biennial Monitoring	$1,412	$1,161		$1,161	1.28	0.55	$2,118	0.356	0.152	$7,618	0.0134	0.0057	$202,208
Baseline - Low Production Oil Well (GOR > 300)	-----	-----	-----	-----	2.63	-----	-----	0.731	-----	-----	0.0276	-----	-----
Stepped Monitoring	$1,445	$2,259		$2,259	1.44	1.19	$1,893	0.400	0.332	$6,812	0.0151	0.0125	$180,806
Semiannual Monitoring	$1,478	$3,213		$3,213	1.19	1.44	$2,229	0.331	0.401	$8,018	0.0125	0.0151	$212,827
Annual Monitoring	$1,434	$1,845		$1,845	1.52	1.11	$1,662	0.423	0.309	$5,980	0.0159	0.0116	$158,719
Biennial Monitoring	$1,412	$1,161		$1,161	1.84	0.79	$1,472	0.512	0.219	$5,294	0.0193	0.0083	$140,515

[1] Capital cost includes cost for implementing the monitoring program of divided between 22 well sites per company.

[2] Annual cost is the annual, semiannual, or stepped monitoring costs, as applicable, and amortization of capital cost over 8 years at 7% interest.

[3] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

Average Model Plant Cost of Control Summary for Well Pads w/ Recovery Credits - M21 Monitoring (10,000 ppm Leak Definition) - Single-Pollutant

Model Plant	Total Capital Investment[1]	Annual LDAR Cost ($/yr)[2]	Recovery Credits ($/yr)[3]	Annual LDAR Cost w/ Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions (Tons/yr)	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions (Tons/yr)	VOC Cost Effectiveness ($/Ton)	HAP Emissions (Tons/yr)	HAP Emission Reductions (Tons/yr)	HAP Cost Effectiveness ($/Ton)
Model Plant													
Baseline - Gas Wells	-----	-----	-----	-----	5.91	-----	-----	1.643	-----	-----	0.0619	-----	-----
Stepped Monitoring	$1,445	$2,259	$531	$1,728	3.23	2.68	$644	0.898	0.745	$2,318	0.0338	0.0281	$61,535
Semiannual Monitoring	$1,478	$3,213	$642	$2,571	2.67	3.24	$794	0.743	0.901	$2,855	0.0280	0.0339	$75,785
Annual Monitoring	$1,434	$1,845	$494	$1,351	3.42	2.49	$541	0.950	0.694	$1,948	0.0358	0.0261	$51,706
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	2.06	-----	-----	0.572	-----	-----	0.0215	-----	-----
Stepped Monitoring	$1,445	$2,259	$185	$2,074	1.12	0.93	$2,224	0.312	0.259	$8,002	0.0118	0.0098	$212,403
Semiannual Monitoring	$1,478	$3,213	$223	$2,990	0.93	1.13	$2,653	0.258	0.313	$9,546	0.0097	0.0118	$253,372
Annual Monitoring	$1,434	$1,845	$172	$1,673	1.19	0.87	$1,928	0.330	0.241	$6,938	0.0124	0.0091	$184,144
Baseline - Oil Well (GOR > 300)	-----	-----	-----	-----	3.04	-----	-----	0.845	-----	-----	0.0318	-----	-----
Stepped Monitoring	$1,445	$2,259	$273	$1,986	1.66	1.38	$1,440	0.462	0.383	$5,181	0.0174	0.0144	$137,528
Semiannual Monitoring	$1,478	$3,213	$330	$2,883	1.37	1.67	$1,730	0.382	0.463	$6,225	0.0144	0.0174	$165,236
Annual Monitoring	$1,434	$1,845	$254	$1,591	1.76	1.28	$1,240	0.489	0.357	$4,461	0.0184	0.0134	$118,416
Baseline - Low Production (<15 BOE)	-----	-----	-----	-----	4.80	-----	-----	1.335	-----	-----	0.0503	-----	-----
Stepped Monitoring	$1,445	$2,259	$432	$1,828	2.62	2.18	$839	0.730	0.605	$3,018	0.0275	0.0228	$80,120
Semiannual Monitoring	$1,478	$3,213	$522	$2,692	2.17	2.63	$1,023	0.603	0.732	$3,679	0.0227	0.0276	$97,661
Annual Monitoring	$1,434	$1,845	$402	$1,444	2.78	2.03	$712	0.772	0.563	$2,563	0.0291	0.0212	$68,020
Biennial Monitoring	$1,412	$1,161	$286	$876	3.36	1.44	$608	0.935	0.401	$2,187	0.0352	0.0151	$58,048
Baseline - Low Production Oil Well (GOR < 300)	-----	-----	-----	-----	1.83	-----	-----	0.508	-----	-----	0.0191	-----	-----
Stepped Monitoring	$1,445	$2,259	$164	$2,095	1.00	0.83	$2,527	0.278	0.230	$9,089	0.0105	0.0087	$241,263
Semiannual Monitoring	$1,478	$3,213	$199	$3,015	0.83	1.00	$3,009	0.230	0.279	$10,825	0.0087	0.0105	$287,343
Annual Monitoring	$1,434	$1,845	$153	$1,693	1.06	0.77	$2,194	0.294	0.214	$7,892	0.0111	0.0081	$209,479
Biennial Monitoring	$1,412	$1,161	$109	$1,053	1.28	0.55	$1,919	0.356	0.152	$6,905	0.0134	0.0057	$183,282
Baseline - Low Production Oil Well (GOR > 300)	-----	-----	-----	-----	2.63	-----	-----	0.731	-----	-----	0.0276	-----	-----
Stepped Monitoring	$1,445	$2,259	$236	$2,023	1.44	1.19	$1,695	0.400	0.332	$6,099	0.0151	0.0125	$161,881
Semiannual Monitoring	$1,478	$3,213	$286	$2,928	1.19	1.44	$2,031	0.331	0.401	$7,305	0.0125	0.0151	$193,901
Annual Monitoring	$1,434	$1,845	$220	$1,625	1.52	1.11	$1,464	0.423	0.309	$5,267	0.0159	0.0116	$139,793
Biennial Monitoring	$1,412	$1,161	$156	$1,005	1.84	0.79	$1,273	0.512	0.219	$4,581	0.0193	0.0083	$121,589

[1] Capital cost includes cost for implementing the monitoring program of divided between 22 well sites per company.

[2] Annual cost is the annual, semiannual, or stepped monitoring costs, as applicable, and amortization of capital cost over 8 years at 7% interest.

[3] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

Emission Reduction =

0.674	Quarterly	155	Natural gas Mscf/yr savings - Natural Gas Well Sites
0.548	Semiannual	188	
0.422	Annual	145	
0.3	Biennial	84	
	Quarterly	54	Natural gas Mscf/yr savings - Oil Well Sites
	Semiannual	65	
	Annual	50	
	Biennial	32	

Well Pad Emission Summary

Model Plant

	Model Plant Component Count						Methane Emissions (Tons/yr)							VOC Emissions (Tons/yr)							HAP Emissions (Tons/yr)						
EF Source	Valves	Flanges	Connectors	Open-Ended Lines	Pressure Relief Valves	Thief Hatches	Valves	Flanges	Connectors	Open-Ended Lines	Pressure Relief Valves	Thief Hatches	Total CH4 Emissions	Valves	Flanges	Connectors	Open-Ended Lines	Pressure Relief Valves	Thief Hatches	Total VOC Emissions	Valves	Flanges	Connectors	Open-Ended Lines	Pressure Relief Valves	Thief Hatches	Total HAP Emissions
Gas Well Sites - GHGI	127	0	462	14	7	1	3.826	0.000	0.619	0.187	0.412	0.868	5.912	1.064	0.000	0.172	0.052	0.115	0.241	1.643	0.040	0.000	0.006	0.002	0.004	0.009	0.062
Oil Well Sites - GHGI	29	54	42	0	2	1	0.874	0.141	0.056	0.000	0.118	0.868	2.056	0.243	0.039	0.016	0.000	0.033	0.241	0.572	0.009	0.001	0.001	0.000	0.001	0.009	0.022

Oil Well w/ Associated Gas	55	54	138	1	3	1	1.657	0.141	0.185	0.013	0.177	0.868	3.041	0.461	0.039	0.051	0.004	0.049	0.241	0.845	0.017	0.001	0.002	0.000	0.002	0.009	0.032
LP Gas Well Sites - FW	100	0	349	12	5	1	3.013	0.000	0.467	0.161	0.295	0.868	4.803	0.837	0.000	0.130	0.045	0.082	0.241	1.335	0.032	0.000	0.005	0.002	0.003	0.009	0.050
LP Oil Well Sites - GHGI	23	41	32	0	2	1	0.693	0.107	0.043	0.000	0.118	0.868	1.828	0.193	0.030	0.012	0.000	0.033	0.241	0.508	0.007	0.001	0.000	0.000	0.001	0.009	0.019
LP Oil Well w/ Associated Gas	44	41	105	1	3	1	1.326	0.107	0.141	0.013	0.177	0.868	2.631	0.368	0.030	0.039	0.004	0.049	0.241	0.731	0.014	0.001	0.001	0.000	0.002	0.009	0.028

Equipment Leaks Protocol TOC Emission Factors[1]

	Uncontrolled (kg/hr/comp)
Valves	0.0045
Flanges	0.00039
Connectors	0.0002
OEL	0.002
PRV	0.0088
Thief Hatches[2]	0.1296

[1] TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service

[2] Thief hatch emission factors are based on information obtained from Lyon, D., et al. "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," Environ. Sci. Technol. 2016, 50, 4877-4886. We have used 1g/s for emissions from thief hatches and tank vents because the study represents this as the minimum detection limit for these sources which have emissions composed primarily of higher hydrocarbon

Average Model Plant Cost of Control for Well Pads w/o Recovery Credits - M21 Monitoring (500 ppm Leak Definition) - Single-pollutant

Model Plant	Total Capital Investment[1]	Annual LDAR Cost ($/yr)[2]	Recovery Credits ($/yr)[3]	Annual LDAR Cost w/o Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions (Tons/yr)	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions (Tons/yr)	VOC Cost Effectiveness ($/Ton)	HAP Emissions (Tons/yr)	HAP Emission Reductions (Tons/yr)	HAP Cost Effectiveness ($/Ton)
Model Plant													
Baseline - Gas Wells	-----	-----	-----	-----	5.91	-----	-----	1.643	-----	-----	0.0619	-----	-----
Stepped Monitoring	$1,445	$2,259		$2,259	1.77	4.14	$545	0.492	1.152	$1,962	0.0185	0.0434	$52,071
Semiannual Monitoring	$1,478	$3,213		$3,213	1.45	4.46	$721	0.404	1.239	$2,593	0.0152	0.0467	$68,835
Annual Monitoring	$1,434	$1,845		$1,845	1.87	4.04	$457	0.521	1.122	$1,644	0.0196	0.0423	$43,641
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	2.06	-----	-----	0.572	-----	-----	0.0215	-----	-----
Stepped Monitoring	$1,445	$2,259		$2,259	0.62	1.44	$1,568	0.171	0.401	$5,640	0.0064	0.0151	$149,708
Semiannual Monitoring	$1,478	$3,213		$3,213	0.51	1.55	$2,073	0.141	0.431	$7,456	0.0053	0.0162	$197,903
Annual Monitoring	$1,434	$1,845		$1,845	0.65	1.40	$1,314	0.181	0.390	$4,727	0.0068	0.0147	$125,469
Baseline - Oil Well (GOR > 300)	-----	-----	-----	-----	3.04	-----	-----	0.845	-----	-----	0.0318	-----	-----
Stepped Monitoring	$1,445	$2,259		$2,259	0.91	2.13	$1,060	0.253	0.592	$3,815	0.0095	0.0223	$101,251
Semiannual Monitoring	$1,478	$3,213		$3,213	0.75	2.29	$1,402	0.208	0.637	$5,043	0.0078	0.0240	$133,847
Annual Monitoring	$1,434	$1,845		$1,845	0.96	2.08	$889	0.268	0.577	$3,197	0.0101	0.0217	$84,858
Baseline - Low Production (<15 BOE)	-----	-----	-----	-----	4.80	-----	-----	1.335	-----	-----	0.0503	-----	-----
Stepped Monitoring	$1,445	$2,259		$2,259	1.44	3.37	$671	0.400	0.936	$2,415	0.0151	0.0352	$64,098
Semiannual Monitoring	$1,478	$3,213		$3,213	1.18	3.62	$887	0.328	1.007	$3,192	0.0124	0.0379	$84,734
Annual Monitoring	$1,434	$1,845		$1,845	1.52	3.28	$563	0.423	0.912	$2,024	0.0159	0.0344	$53,720
Biennial Monitoring	$1,412	$1,161		$1,161	1.87	2.93	$396	0.521	0.814	$1,426	0.0196	0.0307	$37,856
Baseline - Low Production Oil Well (GOR < 300)	-----	-----	-----	-----	1.83	-----	-----	0.508	-----	-----	0.0191	-----	-----
Stepped Monitoring	$1,445	$2,259		$2,259	0.55	1.28	$1,763	0.152	0.356	$6,344	0.0057	0.0134	$168,385
Semiannual Monitoring	$1,478	$3,213		$3,213	0.45	1.38	$2,331	0.125	0.383	$8,386	0.0047	0.0144	$222,593
Annual Monitoring	$1,434	$1,845		$1,845	0.58	1.25	$1,478	0.161	0.347	$5,317	0.0061	0.0131	$141,122
Biennial Monitoring	$1,412	$1,161		$1,161	0.71	1.12	$1,041	0.198	0.310	$3,747	0.0075	0.0117	$99,446
Baseline - Low Production Oil Well (GOR > 300)	-----	-----	-----	-----	2.63	-----	-----	0.731	-----	-----	0.0276	-----	-----
Stepped Monitoring	$1,445	$2,259		$2,259	0.79	1.84	$1,225	0.219	0.512	$4,408	0.0082	0.0193	$117,011
Semiannual Monitoring	$1,478	$3,213		$3,213	0.65	1.98	$1,620	0.180	0.551	$5,827	0.0068	0.0208	$154,680
Annual Monitoring	$1,434	$1,845		$1,845	0.83	1.80	$1,027	0.232	0.500	$3,695	0.0087	0.0188	$98,066
Biennial Monitoring	$1,412	$1,161		$1,161	1.03	1.60	$724	0.285	0.446	$2,604	0.0107	0.0168	$69,106

[1] Capital cost includes cost for implementing the monitoring program divided between 22 well sites per company.

[2] Annual cost is the annual, semiannual, or stepped monitoring costs, as applicable, and amortization of capital cost over 8 years at 7% interest.

[3] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

Average Model Plant Cost of Control Summary for Well Pads w/ Recovery Credits - M21 Monitoring (500 ppm Leak Definition) - Single-Pollutant

Model Plant	Total Capital Investment[1]	Annual LDAR Cost ($/yr)[2]	Recovery Credits ($/yr)[3]	Annual LDAR Cost w/ Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions (Tons/yr)	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions (Tons/yr)	VOC Cost Effectiveness ($/Ton)	HAP Emissions (Tons/yr)	HAP Emission Reductions (Tons/yr)	HAP Cost Effectiveness ($/Ton)
Model Plant													
Baseline - Gas Wells	-----	-----	-----	-----	5.91	-----	-----	1.643	-----	-----	0.0619	-----	-----
Stepped Monitoring	$1,445	$2,259	$821	$1,438	1.77	4.14	$347	0.492	1.152	$1,249	0.0185	0.0434	$33,146
Semiannual Monitoring	$1,478	$3,213	$884	$2,330	1.45	4.46	$523	0.404	1.239	$1,880	0.0152	0.0467	$49,909
Annual Monitoring	$1,434	$1,845	$800	$1,045	1.87	4.04	$259	0.521	1.122	$931	0.0196	0.0423	$24,715
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	2.06	-----	-----	0.572	-----	-----	0.0215	-----	-----
Stepped Monitoring	$1,445	$2,259	$286	$1,974	0.62	1.44	$1,370	0.171	0.401	$4,927	0.0064	0.0151	$130,782
Semiannual Monitoring	$1,478	$3,213	$307	$2,906	0.51	1.55	$1,874	0.141	0.431	$6,743	0.0053	0.0162	$178,977
Annual Monitoring	$1,434	$1,845	$278	$1,567	0.65	1.40	$1,116	0.181	0.390	$4,014	0.0068	0.0147	$106,544
Baseline - Oil Well (GOR > 300)	-----	-----	-----	-----	3.04	-----	-----	0.845	-----	-----	0.0318	-----	-----
Stepped Monitoring	$1,445	$2,259	$422	$1,837	0.91	2.13	$862	0.253	0.592	$3,102	0.0095	0.0223	$82,326
Semiannual Monitoring	$1,478	$3,213	$454	$2,759	0.75	2.29	$1,204	0.208	0.637	$4,330	0.0078	0.0240	$114,921
Annual Monitoring	$1,434	$1,845	$412	$1,434	0.96	2.08	$690	0.268	0.577	$2,484	0.0101	0.0217	$65,933
Baseline - Low Production (<15 BOE)	-----	-----	-----	-----	4.80	-----	-----	1.335	-----	-----	0.0503	-----	-----
Stepped Monitoring	$1,445	$2,259	$667	$1,592	1.44	3.37	$473	0.400	0.936	$1,702	0.0151	0.0352	$45,173
Semiannual Monitoring	$1,478	$3,213	$718	$2,496	1.18	3.62	$689	0.328	1.007	$2,479	0.0124	0.0379	$65,808
Annual Monitoring	$1,434	$1,845	$650	$1,195	1.52	3.28	$364	0.423	0.912	$1,311	0.0159	0.0344	$34,795
Biennial Monitoring	$1,412	$1,161	$581	$581	1.87	2.93	$396	0.521	0.814	$1,426	0.0196	0.0307	$37,856
Baseline - Low Production Oil Well (GOR < 300)	-----	-----	-----	-----	1.83	-----	-----	0.508	-----	-----	0.0191	-----	-----
Stepped Monitoring	$1,445	$2,259	$254	$2,005	0.55	1.28	$1,565	0.152	0.356	$5,631	0.0057	0.0134	$149,459
Semiannual Monitoring	$1,478	$3,213	$273	$2,940	0.45	1.38	$2,133	0.125	0.383	$7,673	0.0047	0.0144	$203,667
Annual Monitoring	$1,434	$1,845	$247	$1,598	0.58	1.25	$1,280	0.161	0.347	$4,604	0.0061	0.0131	$122,197
Biennial Monitoring	$1,412	$1,161	$221	$940	0.71	1.12	$1,041	0.198	0.310	$3,747	0.0075	0.0117	$99,446
Baseline - Low Production Oil Well (GOR > 300)	-----	-----	-----	-----	2.63	-----	-----	0.731	-----	-----	0.0276	-----	-----
Stepped Monitoring	$1,445	$2,259	$365	$1,894	0.79	1.84	$1,027	0.219	0.512	$3,695	0.0082	0.0193	$98,086
Semiannual Monitoring	$1,478	$3,213	$393	$2,820	0.65	1.98	$1,422	0.180	0.551	$5,114	0.0068	0.0208	$135,755
Annual Monitoring	$1,434	$1,845	$356	$1,489	0.83	1.80	$829	0.232	0.500	$2,982	0.0087	0.0188	$79,141
Biennial Monitoring	$1,412	$1,161	$318	$843	1.03	1.60	$724	0.285	0.446	$2,604	0.0107	0.0168	$69,106

[1] Capital cost includes cost for implementing the monitoring program divided between 22 well sites per company.

[2] Annual cost is the annual, semiannual, or stepped monitoring costs, as applicable, and amortization of capital cost over 8 years at 7% interest.

[3] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

Emission Reduction =

0.825	Quarterly	240	Natural gas Mscf/yr savings - Natural Gas Well Sites
0.754	Semiannual	258	
0.683	Annual	234	
0.61	Biennial	170	
	Quarterly	84	Natural gas Mscf/yr savings - Oil Well Sites
	Semiannual	90	
	Annual	81	
	Biennial	65	

Well Pad Emission Summary

Model Plant

	Model Plant Component Count						Methane Emissions (Tons/yr)							VOC Emissions (Tons/yr)							HAP Emissions (Tons/yr)						
EF Source	Valves	Flanges	Connectors	Open-Ended Lines	Pressure Relief Valves	Thief Hatches	Valves	Flanges	Connectors	Open-Ended Lines	Pressure Relief Valves	Thief Hatches	Total CH4 Emissions	Valves	Flanges	Connectors	Open-Ended Lines	Pressure Relief Valves	Thief Hatches	Total VOC Emissions	Valves	Flanges	Connectors	Open-Ended Lines	Pressure Relief Valves	Thief Hatches	Total HAP Emissions
Gas Well Sites - GHGI	127	0	462	14	7	1	3.826	0.000	0.619	0.187	0.412	0.868	5.912	1.064	0.000	0.172	0.052	0.115	0.241	1.643	0.040	0.000	0.006	0.002	0.004	0.009	0.062
Oil Well Sites - GHGI	29	54	42	0	2	1	0.874	0.141	0.056	0.000	0.118	0.868	2.056	0.243	0.039	0.016	0.000	0.033	0.241	0.572	0.009	0.001	0.001	0.000	0.001	0.009	0.022
Oil Well w/ Associated Gas	55	54	138	1	3	1	1.657	0.141	0.185	0.013	0.177	0.868	3.041	0.461	0.039	0.051	0.004	0.049	0.241	0.845	0.017	0.001	0.002	0.000	0.002	0.009	0.032
LP Gas Well Sites - FW	100	0	349	12	5	1	3.013	0.000	0.467	0.161	0.295	0.868	4.803	0.837	0.000	0.130	0.045	0.082	0.241	1.335	0.032	0.000	0.005	0.002	0.003	0.009	0.050

LP Oil Well Sites - GHGI	23	41	32	0	2	1	0.693	0.107	0.043	0.000	0.118	0.868	1.828	0.193	0.030	0.012	0.000	0.033	0.241	0.508	0.007	0.001	0.000	0.000	0.001	0.009	0.019
LP Oil Well w/ Associated Gas	44	41	105	1	3	1	1.326	0.107	0.141	0.013	0.177	0.868	2.631	0.368	0.030	0.039	0.004	0.049	0.241	0.731	0.014	0.001	0.001	0.000	0.002	0.009	0.028

Equipment Leaks Protocol TOC Emission Factors[1]

	Uncontrolled (kg/hr/comp)
Valves	0.0045
Flanges	0.00039
Connectors	0.0002
OEL	0.002
PRV	0.0088
Thief Hatches[2]	0.1296

[1] TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service

[2] Thief hatch emission factors are based on information obtained from Lyon, D., et al. "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," Environ. Sci. Technol. 2016, 50, 4877-4886. We have used 1g/s for emissions from thief hatches and tank vents because the study represents this as the minimum detection limit for these sources which have emissions composed primarily of higher hydrocarbons.

Model Plant 2015 - Single Pollutant
Method 21 Monitoring & Repair Plan 10,000 ppm - High Production Oil & Natural Gas Production Well Sites

Category	Number of New Sources[1]	Model Plant Capital Cost ($)[2]	Model Plant Annual Cost ($/yr)[3]	Model Plant Annual Cost w/Savings ($/yr)[4]	Emis Reduc Methan e
Stepped M21 Monitoring - Single Pollutant					
Gas Well Sites	2,001	$1,445	$2,259	$1,728	2.68
Oil Well Sites (GOR < 300)	1,848	$1,445	$2,259	$2,074	0.93
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$1,445	$2,259	$1,986	1.38
All Wells Weighted Averages					
Annual M21 Monitoring - Single Pollutant					
Gas Well Sites	2,001	$1,434	$1,845	$1,351	2.49
Oil Well Sites (GOR < 300)	1,848	$1,434	$1,845	$1,673	0.87
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$1,434	$1,845	$1,591	1.28
All Wells Weighted Averages					
Semiannual M21 Monitoring - Single Pollutant					
Gas Well Sites	2,001	$1,478	$3,213	$2,571	3.24
Oil Well Sites (GOR < 300)	1,848	$1,478	$3,213	$2,990	1.13
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$1,478	$3,213	$2,883	1.67
All Wells Weighted Averages					

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR based on data

[2] Capital cost includes costs for reading rule, developing monitoring plan, intial activities planning, notification of initial complia

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 years at 7% int

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf

[5] Assumes 42.2% reduction with annual M21 monitoring, and 54.8% reduction with semiannual M21 monitoring.

Model Plant 2015 - Multi Pollutant
Method 21 Monitoring & Repair Plan 10,000 ppm - High Production Oil & Natural Gas Production Well Sites

Category	Number of New Sources[1]	Capital Cost ($)[2]	Annual Cost ($/yr)[3]	Well Site Annual Cost w/Savings ($/yr)[4]	Natio Emis Methan e
Stepped M21 Monitoring - Multi Pollutant					
Gas Well Sites	2,001	$1,445	$2,259	$1,728	2.68
Oil Well Sites (GOR < 300)	1,848	$1,445	$2,259	$2,074	0.93
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$1,445	$2,259	$1,986	1.38
All Wells Weighted Averages					
Annual M21 Monitoring - Multi Pollutant					
Gas Well Sites	2,001	$1,434	$1,845	$1,351	2.49
Oil Well Sites (GOR < 300)	1,848	$1,434	$1,845	$1,673	0.87
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$1,434	$1,845	$1,591	1.28
All Wells Weighted Averages					
Semiannual M21 Monitoring - Multi Pollutant					
Gas Well Sites	2,001	$1,478	$3,213	$2,571	3.24
Oil Well Sites (GOR < 300)	1,848	$1,478	$3,213	$2,990	1.13
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$1,478	$3,213	$2,883	1.67

sion tions[5]	Methane Cost of Contro		VOC Cost of Control		Nationwide Emission Reductions		Total Nationwide Costs		
VOC (Tons/yr	w/o Savings	w/ Savings	w/o Savings	w/ Savings	Methan e	VOC (Tons/yr	Capital Cost	Annual Cost w/o savings	Annual Cost w/ Savings
0.75	$843	$644	$3,031	$2,318	5,365	1,491	$2,891,244	$4,520,710	$3,457,380
0.26	$2,423	$2,224	$8,715	$8,002	1,723	479	$2,669,451	$4,173,919	$3,832,443
0.38	$1,638	$1,440	$5,894	$5,181	12,671	3,522	$13,277,902	$20,761,150	$18,249,774
	$1,491	**$1,293**	**$5,363**	**$4,650**					
0.69	$740	$541	$2,661	$1,948	4,992	1,388	$2,868,976	$3,692,811	$2,703,340
0.24	$2,127	$1,928	$7,651	$6,938	1,603	446	$2,648,892	$3,409,530	$3,091,773
0.36	$1,438	$1,240	$5,174	$4,461	11,791	3,278	$13,175,639	$16,959,066	$14,622,129
	$1,309	**$1,110**	**$4,708**	**$3,995**					
0.90	$992	$794	$3,568	$2,855	6,483	1,802	$2,958,047	$6,430,183	$5,145,278
0.31	$2,852	$2,653	$10,259	$9,546	2,082	579	$2,731,130	$5,936,913	$5,524,281
0.46	$1,929	$1,730	$6,938	$6,225	15,312	4,256	$13,584,692	$29,530,319	$26,495,624
	$1,755	**$1,557**	**$6,313**	**$5,600**					

a from the HPDI.

nce status, and purchase of M21 monitoring device.

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nwide sion	Methane Cost of Contro		VOC Cost of Control		Nationwide Emission		Total Nationwide Costs		
VOC (Tons/yr	w/o Savings	w/ Savings	w/o Savings	w/ Savings	Methan e	VOC (Tons/yr	Capital Cost	Annual Cost w/o savings	Annual Cost w/ Savings
0.745	$421	$322	$1,516	$1,159	5,365	1,491	$2,891,244	$4,520,710	$3,457,380
0.259	$1,211	$1,112	$4,358	$4,001	1,723	479	$2,669,451	$4,173,919	$3,832,443
0.383	$819	$720	$2,947	$2,591	12,671	3,522	$13,277,902	$20,761,150	$18,249,774
	$745	**$646**	**$2,681**	**$2,325**					
0.694	$370	$271	$1,331	$974	4,992	1,388	$2,868,976	$3,692,811	$2,703,340
0.241	$1,063	$964	$3,825	$3,469	1,603	446	$2,648,892	$3,409,530	$3,091,773
0.357	$719	$620	$2,587	$2,231	11,791	3,278	$13,175,639	$16,959,066	$14,622,129
	$654	**$555**	**$2,354**	**$1,997**					
0.901	$496	$397	$1,784	$1,428	6,483	1,802	$2,958,047	$6,430,183	$5,145,278
0.313	$1,426	$1,327	$5,129	$4,773	2,082	579	$2,731,130	$5,936,913	$5,524,281
0.463	$964	$865	$3,469	$3,113	15,312	4,256	$13,584,692	$29,530,319	$26,495,624

All Wells Weighted Averages

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR based on data

[2] Capital cost includes costs for reading rule, developing monitoring plan, intial activities planning, notification of initial complia

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 years at 7% int

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf

[5] Assumes 42.2% reduction with annual M21 monitoring, and 54.8% reduction with semiannual M21 monitoring.

	$877	**$778**	**$3,156**	**$2,800**	

a from the HPDI.

nce status, and purchase of M21 monitoring device.

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Model Plant 2015 - Single Pollutant
Method 21 Monitoring & Repair Plan 500 ppm - High Production Oil & Natural Gas Production Well Sites

Category	Number of New Sources[1]	Model Plant Capital Cost ($)[2]	Model Plant Annual Cost ($/yr)[3]	Model Plant Annual Cost w/Savings ($/yr)[4]	Emis Reduc Methan e
Stepped M21 Monitoring - Single Pollutant					
Gas Well Sites	2,001	$1,445	$2,259	$1,438	4.14
Oil Well Sites (GOR < 300)	1,848	$1,445	$2,259	$1,974	1.44
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$1,445	$2,259	$1,837	2.13
All Wells Weighted Averages					
Annual M21 Monitoring - Single Pollutant					
Gas Well Sites	2,001	$1,434	$1,845	$1,045	4.04
Oil Well Sites (GOR < 300)	1,848	$1,434	$1,845	$1,567	1.40
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$1,434	$1,845	$1,434	2.08
All Wells Weighted Averages					
Semiannual M21 Monitoring - Single Pollutant					
Gas Well Sites	2,001	$1,478	$3,213	$2,330	4.46
Oil Well Sites (GOR < 300)	1,848	$1,478	$3,213	$2,906	1.55
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$1,478	$3,213	$2,759	2.29
All Wells Weighted Averages					

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR based on data

[2] Capital cost includes costs for reading rule, developing monitoring plan, intial activities planning, notification of initial complia

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 years at 7% int

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf

[5] Assumes 68.3% reduction with annual M21 monitoring and 75.4% reduction with semiannual M21 monitoring.

Model Plant 2015 - Multi Pollutant
Method 21 Monitoring & Repair Plan 500 ppm - High Production Oil & Natural Gas Production Well Sites

Category	Number of New Sources[1]	Capital Cost ($)[2]	Annual Cost ($/yr)[3]	Well Site Annual Cost w/Savings ($/yr)[4]	Natio Emis Methan e
Stepped M21 Monitoring - Multi Pollutant					
Gas Well Sites	2,001	$1,445	$2,259	$1,438	4.14
Oil Well Sites (GOR < 300)	1,848	$1,445	$2,259	$1,974	1.44
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$1,445	$2,259	$1,837	2.13
All Wells Weighted Averages					
Annual M21 Monitoring - Multi Pollutant					
Gas Well Sites	2,001	$1,434	$1,845	$1,045	4.04
Oil Well Sites (GOR < 300)	1,848	$1,434	$1,845	$1,567	1.40
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$1,434	$1,845	$1,434	2.08
All Wells Weighted Averages					
Semiannual M21 Monitoring - Multi Pollutant					
Gas Well Sites	2,001	$1,478	$3,213	$2,330	4.46
Oil Well Sites (GOR < 300)	1,848	$1,478	$3,213	$2,906	1.55
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$1,478	$3,213	$2,759	2.29

sion tions[5]	Methane Cost of Contro		VOC Cost of Control		Nationwide Emission Reductions		Total Nationwide Costs		
VOC (Tons/yr	w/o Savings	w/ Savings	w/o Savings	w/ Savings	Methan e	VOC (Tons/yr	Capital Cost	Annual Cost w/o savings	Annual Cost w/ Savings
1.15	$545	$347	$1,962	$1,249	8,290	2,304	$2,891,244	$4,520,710	$2,877,649
0.40	$1,568	$1,370	$5,640	$4,927	2,662	740	$2,669,451	$4,173,919	$3,646,269
0.59	$1,060	$862	$3,815	$3,102	19,579	5,443	$13,277,902	$20,761,150	$16,880,562
	$965	**$767**	**$3,471**	**$2,758**					
1.12	$457	$259	$1,644	$931	8,080	2,246	$2,868,976	$3,692,811	$2,091,369
0.39	$1,314	$1,116	$4,727	$4,014	2,595	721	$2,648,892	$3,409,530	$2,895,245
0.58	$889	$690	$3,197	$2,484	19,084	5,305	$13,175,639	$16,959,066	$13,176,773
	$809	**$610**	**$2,909**	**$2,196**					
1.24	$721	$523	$2,593	$1,880	8,920	2,480	$2,958,047	$6,430,183	$4,662,266
0.43	$2,073	$1,874	$7,456	$6,743	2,865	796	$2,731,130	$5,936,913	$5,369,167
0.64	$1,402	$1,204	$5,043	$4,330	21,067	5,856	$13,584,692	$29,530,319	$25,354,845
	$1,275	**$1,077**	**$4,588**	**$3,875**					

a from the HPDI.

nce status, and purchase of M21 monitoring device.

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nwide sion	Methane Cost of Contro		VOC Cost of Control		Nationwide Emission		Total Nationwide Costs		
VOC (Tons/yr	w/o Savings	w/ Savings	w/o Savings	w/ Savings	Methan e	VOC (Tons/yr	Capital Cost	Annual Cost w/o savings	Annual Cost w/ Savings
1.152	$273	$174	$981	$624	8,290	2,304	$2,891,244	$4,520,710	$2,877,649
0.401	$784	$685	$2,820	$2,464	2,662	740	$2,669,451	$4,173,919	$3,646,269
0.592	$530	$431	$1,907	$1,551	19,579	5,443	$13,277,902	$20,761,150	$16,880,562
	$482	**$383**	**$1,735**	**$1,379**					
1.122	$229	$129	$822	$466	8,080	2,246	$2,868,976	$3,692,811	$2,091,369
0.390	$657	$558	$2,363	$2,007	2,595	721	$2,648,892	$3,409,530	$2,895,245
0.577	$444	$345	$1,598	$1,242	19,084	5,305	$13,175,639	$16,959,066	$13,176,773
	$404	**$305**	**$1,454**	**$1,098**					
1.239	$360	$261	$1,297	$940	8,920	2,480	$2,958,047	$6,430,183	$4,662,266
0.431	$1,036	$937	$3,728	$3,371	2,865	796	$2,731,130	$5,936,913	$5,369,167
0.637	$701	$602	$2,521	$2,165	21,067	5,856	$13,584,692	$29,530,319	$25,354,845

All Wells Weighted Averages

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR based on data

[2] Capital cost includes costs for reading rule, developing monitoring plan, intial activities planning, notification of initial complia

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 years at 7% int

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf

[5] Assumes 68.3% reduction with annual M21 monitoring and 75.4% reduction with semiannual M21 monitoring.

	$638	**$539**	**$2,294**	**$1,937**	

a from the HPDI.

nce status, and purchase of M21 monitoring device.

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Model Plant 2015 - Single Pollutant

Method 21 Monitoring & Repair Plan 10,000 ppm - Low Production Oil & Natural Gas Production Well Sites (<15 E

Category	Number of New Sources[1]	Model Plant Capital Cost ($)[2]	Model Plant Annual Cost ($/yr)[3]
Biennial M21 Monitoring - Single Pollutant			
Low Production Gas Well Sites	409	$1,412	$1,161
Low Production Oil Well Sites (GOR < 300)	2,171	$1,412	$1,161
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$1,412	$1,161
All Wells Weighted Averages			
Stepped M21 Monitoring - Single Pollutant			
Low Production Gas Well Sites	409	$1,445	$2,259
Low Production Oil Well Sites (GOR < 300)	2,171	$1,445	$2,259
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$1,445	$2,259
All Wells Weighted Averages			
Annual M21 Monitoring - Single Pollutant			
Low Production Gas Well Sites	409	$1,434	$1,845
Low Production Oil Well Sites (GOR < 300)	2,171	$1,434	$1,845
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$1,434	$1,845
All Wells Weighted Averages			
Semiannual M21 Monitoring - Single Pollutant			
Low Production Gas Well Sites	409	$1,478	$3,213
Low Production Oil Well Sites (GOR < 300)	2,171	$1,478	$3,213
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$1,478	$3,213
All Wells Weighted Averages			

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR ba

[2] Capital cost includes costs for reading rule, developing monitoring plan, intial activities planning, notification of init

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 yea

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of

[5] Assumes 42.2% reduction with annual M21 monitoring and 54.8% reduction with semiannual M21 monitoring.

Model Plant 2015 - Multi Pollutant

Method 21 Monitoring & Repair Plan 10,000 ppm - Low Production Oil & Natural Gas Production Well Sites (<15 E

Category	Number of New Sources[1]	Capital Cost ($)[2]	Annual Cost ($/yr)[3]
Biennial M21 Monitoring - Multi Pollutant			
Low Production Gas Well Sites	409	$1,412	$1,161
Low Production Oil Well Sites (GOR < 300)	2,171	$1,412	$1,161
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$1,412	$1,161

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Model Plant Annual Cost w/Savings ($/yr)[4]	Emission Reductions[5]		Methane Cost of Contro		VOC Cost of Control		Emission Reductions		Total
	Methan e	VOC (Tons/yr	w/o Savings	w/ Savings	w/o Savings	w/ Savings	Methan e	VOC (Tons/yr	Capital Cost
$876	1.44	0.401	$806	$608	$2,900	$2,187	589	164	$576,604
$1,053	0.55	0.152	$2,118	$1,919	$7,618	$6,905	1,190	331	$3,063,692
$1,005	0.79	0.219	$1,472	$1,273	$5,294	$4,581	965	268	$1,724,871
			$1,609	**$1,411**	**$5,789**	**$5,076**			
$1,828	2.18	0.61	$1,037	$839	$3,731	$3,018	890	247	$590,241
$2,095	0.83	0.23	$2,725	$2,527	$9,802	$9,089	1,800	500	$3,136,154
$2,023	1.19	0.33	$1,893	$1,695	$6,812	$6,099	1,458	405	$1,765,667
			$2,071	**$1,872**	**$7,449**	**$6,736**			
$1,444	2.03	0.56	$911	$712	$3,276	$2,563	828	230	$585,695
$1,693	0.77	0.21	$2,392	$2,194	$8,605	$7,892	1,675	466	$3,112,000
$1,625	1.11	0.31	$1,662	$1,464	$5,980	$5,267	1,357	377	$1,752,068
			$1,818	**$1,619**	**$6,539**	**$5,826**			
$2,692	2.63	0.73	$1,221	$1,023	$4,392	$3,679	1,075	299	$603,879
$3,015	1.00	0.28	$3,207	$3,009	$11,538	$10,825	2,175	604	$3,208,616
$2,928	1.44	0.40	$2,229	$2,031	$8,018	$7,305	1,762	490	$1,806,463
			$2,437	**$2,239**	**$8,768**	**$8,055**			

sed on data from the HPDI.

ial compliance status, and purchase of M21 monitoring device.

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$3.42/Mscf.

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Well Site Annual Cost w/Savings ($/yr)[4]	Nationwide Emission		Methane Cost of Contro		VOC Cost of Control		Nationwide Emission		Total
	Methan e	VOC (Tons/yr	w/o Savings	w/ Savings	w/o Savings	w/ Savings	Methan e	VOC (Tons/yr	Capital Cost
$876	1.44	0.401	$403	$304	$1,450	$1,093	589	164	$576,604
$1,053	0.55	0.152	$1,059	$960	$3,809	$3,453	1,190	331	$3,063,692
$1,005	0.79	0.219	$736	$637	$2,647	$2,290	965	268	$1,724,871

Nationwide Costs	
Annual Cost w/o	Annual Cost w/
$474,465	$357,809
$2,520,997	$2,285,046
$1,419,331	$1,228,166
$922,893	$746,548
$4,903,648	$4,546,970
$2,760,773	$2,471,796
$753,880	$589,783
$4,005,621	$3,673,717
$2,255,180	$1,986,275
$1,312,709	$1,099,616
$6,974,869	$6,543,866
$3,926,878	$3,577,684

Nationwide Costs	
Annual Cost w/o	Annual Cost w/
$474,465	$357,809
$2,520,997	$2,285,046
$1,419,331	$1,228,166

All Wells Weighted Averages			
Stepped M21 Monitoring - Multi Pollutant			
Low Production Gas Well Sites	409	$1,445	$2,259
Low Production Oil Well Sites (GOR < 300)	2,171	$1,445	$2,259
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$1,445	$2,259
All Wells Weighted Averages			
Annual M21 Monitoring - Multi Pollutant			
Low Production Gas Well Sites	409	$1,434	$1,845
Low Production Oil Well Sites (GOR < 300)	2,171	$1,434	$1,845
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$1,434	$1,845
All Wells Weighted Averages			
Semiannual M21 Monitoring - Multi Pollutant			
Low Production Gas Well Sites	409	$1,478	$3,213
Low Production Oil Well Sites (GOR < 300)	2,171	$1,478	$3,213
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$1,478	$3,213
All Wells Weighted Averages			

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR ba

[2] Capital cost includes costs for reading rule, developing monitoring plan, intial activities planning, notification of init

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 yea

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of

[5] Assumes 42.2% reduction with annual M21 monitoring and 54.8% reduction with semiannual M21 monitoring.

			$805	**$705**	**$2,894**	**$2,538**			
$1,828	2.18	0.605	$519	$420	$1,866	$1,509	890	247	$590,241
$2,095	0.83	0.230	$1,362	$1,263	$4,901	$4,545	1,800	500	$3,136,154
$2,023	1.19	0.332	$947	$848	$3,406	$3,049	1,458	405	$1,765,667
			$1,035	**$936**	**$3,724**	**$3,368**			
$1,444	2.03	0.563	$455	$356	$1,638	$1,281	828	230	$585,695
$1,693	0.77	0.214	$1,196	$1,097	$4,302	$3,946	1,675	466	$3,112,000
$1,625	1.11	0.309	$831	$732	$2,990	$2,633	1,357	377	$1,752,068
			$909	**$810**	**$3,269**	**$2,913**			
$2,692	2.63	0.732	$610	$511	$2,196	$1,840	1,075	299	$603,879
$3,015	1.00	0.279	$1,604	$1,505	$5,769	$5,413	2,175	604	$3,208,616
$2,928	1.44	0.401	$1,114	$1,015	$4,009	$3,653	1,762	490	$1,806,463
			$1,219	**$1,120**	**$4,384**	**$4,027**			

sed on data from the HPDI.

ial compliance status, and purchase of M21 monitoring device.

ırs at 7% interest.

$3.42/Mscf.

$922,893	$746,548
$4,903,648	$4,546,970
$2,760,773	$2,471,796

$753,880	$589,783
$4,005,621	$3,673,717
$2,255,180	$1,986,275

$1,312,709	$1,099,616
$6,974,869	$6,543,866
$3,926,878	$3,577,684

Model Plant 2015 - Single Pollutant

Method 21 Monitoring & Repair Plan 500 ppm - Low Production Oil & Natural Gas Production Well Sites (<15 BOE

Category	Number of New Sources[1]	Model Plant Capital Cost ($)[2]	Model Plant Annual Cost ($/yr)[3]
Biennial M21 Monitoring - Single Pollutant			
Low Production Gas Well Sites	409	$1,412	$1,161
Low Production Oil Well Sites (GOR < 300)	2,171	$1,412	$1,161
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$1,412	$1,161
All Wells Weighted Averages			
Stepped M21 Monitoring - Single Pollutant			
Low Production Gas Well Sites	409	$1,445	$2,259
Low Production Oil Well Sites (GOR < 300)	2,171	$1,445	$2,259
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$1,445	$2,259
All Wells Weighted Averages			
Annual M21 Monitoring - Single Pollutant			
Low Production Gas Well Sites	409	$1,434	$1,845
Low Production Oil Well Sites (GOR < 300)	2,171	$1,434	$1,845
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$1,434	$1,845
All Wells Weighted Averages			
Semiannual M21 Monitoring - Single Pollutant			
Low Production Gas Well Sites	409	$1,478	$3,213
Low Production Oil Well Sites (GOR < 300)	2,171	$1,478	$3,213
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$1,478	$3,213
All Wells Weighted Averages			

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR ba

[2] Capital cost includes costs for reading rule, developing monitoring plan, intial activities planning, notification of init

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 yea

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of

[5] Assumes 68.3% reduction with annual M21 monitoring and 75.4% reduction with semiannual M21 monitoring.

Model Plant 2015 - Multi Pollutant

Method 21 Monitoring & Repair Plan 500 ppm - Low Production Oil & Natural Gas Production Well Sites (<15 BOE

Category	Number of New Sources[1]	Capital Cost ($)[2]	Annual Cost ($/yr)[3]
Biennial M21 Monitoring - Multi Pollutant			
Low Production Gas Well Sites	409	$1,412	$1,161
Low Production Oil Well Sites (GOR < 300)	2,171	$1,412	$1,161
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$1,412	$1,161

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Model Plant Annual Cost w/Savings ($/yr)[4]	Emission Reductions[5]		Methane Cost of Contro		VOC Cost of Control		Emission Reductions		Total
	Methan e	VOC (Tons/yr	w/o Savings	w/ Savings	w/o Savings	w/ Savings	Methan e	VOC (Tons/yr	Capital Cost
$581	2.93	0.814	$396	$198	$1,426	$713	1,197	333	$576,604
$940	1.12	0.310	$1,041	$843	$3,747	$3,034	2,421	673	$3,063,692
$843	1.60	0.446	$724	$526	$2,604	$1,891	1,961	545	$1,724,871
			$791	**$593**	**$2,847**	**$2,134**			
$1,592	3.37	0.94	$671	$473	$2,415	$1,702	1,375	382	$590,241
$2,005	1.28	0.36	$1,763	$1,565	$6,344	$5,631	2,781	773	$3,136,154
$1,894	1.84	0.51	$1,225	$1,027	$4,408	$3,695	2,253	626	$1,765,667
			$1,340	**$1,142**	**$4,820**	**$4,107**			
$1,195	3.28	0.91	$563	$364	$2,024	$1,311	1,340	372	$585,695
$1,598	1.25	0.35	$1,478	$1,280	$5,317	$4,604	2,710	753	$3,112,000
$1,489	1.80	0.50	$1,027	$829	$3,695	$2,982	2,196	610	$1,752,068
			$1,123	**$925**	**$4,040**	**$3,327**			
$2,496	3.62	1.01	$887	$689	$3,192	$2,479	1,479	411	$603,879
$2,940	1.38	0.38	$2,331	$2,133	$8,386	$7,673	2,992	832	$3,208,616
$2,820	1.98	0.55	$1,620	$1,422	$5,827	$5,114	2,424	674	$1,806,463
			$1,771	**$1,573**	**$6,372**	**$5,659**			

sed on data from the HPDI.

ial compliance status, and purchase of M21 monitoring device.

ırs at 7% interest.

$3.42/Mscf.

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Well Site Annual Cost w/Savings ($/yr)[4]	Nationwide Emission		Methane Cost of Contro		VOC Cost of Control		Nationwide Emission		Total
	Methan e	VOC (Tons/yr	w/o Savings	w/ Savings	w/o Savings	w/ Savings	Methan e	VOC (Tons/yr	Capital Cost
$581	2.93	0.814	$198	$99	$713	$357	1,197	333	$576,604
$940	1.12	0.310	$521	$422	$1,873	$1,517	2,421	673	$3,063,692
$843	1.60	0.446	$362	$263	$1,302	$945	1,961	545	$1,724,871

Nationwide Costs	
Annual Cost w/o	Annual Cost w/
$474,465	$237,264
$2,520,997	$2,041,231
$1,419,331	$1,030,630
$922,893	$650,404
$4,903,648	$4,352,508
$2,760,773	$2,314,244
$753,880	$488,292
$4,005,621	$3,468,441
$2,255,180	$1,819,962
$1,312,709	$1,019,512
$6,974,869	$6,381,847
$3,926,878	$3,446,418

Nationwide Costs	
Annual Cost w/o	Annual Cost w/
$474,465	$237,264
$2,520,997	$2,041,231
$1,419,331	$1,030,630

All Wells Weighted Averages			
Stepped M21 Monitoring - Multi Pollutant			
Low Production Gas Well Sites	409	$1,445	$2,259
Low Production Oil Well Sites (GOR < 300)	2,171	$1,445	$2,259
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$1,445	$2,259
All Wells Weighted Averages			
Annual M21 Monitoring - Multi Pollutant			
Low Production Gas Well Sites	409	$1,434	$1,845
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All Wells Weighted Averages			
Semiannual M21 Monitoring - Multi Pollutant			
Low Production Gas Well Sites	409	$1,478	$3,213
Low Production Oil Well Sites (GOR < 300)	2,171	$1,478	$3,213
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$1,478	$3,213
All Wells Weighted Averages			

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR ba

[2] Capital cost includes costs for reading rule, developing monitoring plan, intial activities planning, notification of init

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 yea

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of

[5] Assumes 68.3% reduction with annual M21 monitoring and 75.4% reduction with semiannual M21 monitoring.

			$396	**$297**	**$1,423**	**$1,067**			
$1,592	3.37	0.936	$336	$237	$1,207	$851	1,375	382	$590,241
$2,005	1.28	0.356	$882	$783	$3,172	$2,815	2,781	773	$3,136,154
$1,894	1.84	0.512	$613	$514	$2,204	$1,848	2,253	626	$1,765,667
			$670	**$571**	**$2,410**	**$2,054**			
$1,195	3.28	0.912	$281	$182	$1,012	$655	1,340	372	$585,695
$1,598	1.25	0.347	$739	$640	$2,658	$2,302	2,710	753	$3,112,000
$1,489	1.80	0.500	$513	$414	$1,847	$1,491	2,196	610	$1,752,068
			$562	**$462**	**$2,020**	**$1,664**			
$2,496	3.62	1.007	$444	$345	$1,596	$1,240	1,479	411	$603,879
$2,940	1.38	0.383	$1,166	$1,066	$4,193	$3,837	2,992	832	$3,208,616
$2,820	1.98	0.551	$810	$711	$2,914	$2,557	2,424	674	$1,806,463
			$886	**$787**	**$3,186**	**$2,830**			

sed on data from the HPDI.

ial compliance status, and purchase of M21 monitoring device.

ırs at 7% interest.

$3.42/Mscf.

$922,893	$650,404
$4,903,648	$4,352,508
$2,760,773	$2,314,244

$753,880	$488,292
$4,005,621	$3,468,441
$2,255,180	$1,819,962

$1,312,709	$1,019,512
$6,974,869	$6,381,847
$3,926,878	$3,446,418

Conversion of volume methane to mass methane

0.02082	tons methane/1000 scf	41.63	lbs/1000 scf
		0.0416	lbs/scf

Weight Ratios to Use in Estimating Emissions

	Production	Transmission
Methane:TOC	0.694769295	0.90771035
VOC:TOC	0.193128289	0.0251206
HAP:TOC	0.007275976	0.00074612
VOC:Methane	0.277974703	0.02767469
HAP:Methane	0.010472507	0.00082199
BTEX:Methane	0.002796071	0.000322
HAP:VOC	0.037674316	0.02970169
BTEX:VOC	0.010058724	0.01163501

Volume Ratios to Use in Estimating Natural Gas Savings

	Production	Transmission
Methane:Gas	82.9%	92.8%

Natural Gas Cost Used For Savings $3.42 /1000 ft3 natural gas

2015 Activity Data from GHGI

Total Active Gas	421,893
Heaters	87,087
Separators	289,046
Dehydrators	11,235
Meters/Piping	361,753
Compressors	33,026
Chemical Injecti	79,806
Total Oil Wells	586,896
Oil Wellheads (l	41,376
Oil Wellheads (l	545,520
Separators (hea	23,105
Separators (ligh	210,281
Heater/Treaters	137,378
Headers (heavy	34,490
Headers (light c	106,922
Chemical Injecti	53,281

Spreadsheet Descriptions

Gas Well Pad MP
Oil Well Pad MP
Oil_Gas Well Pad MP
Gas Well Only MP
Oil Well Only MP
Oil_Gas Well Only MP
LP Gas Well Pad MP
LP Oil Well Pad MP
LP Oil_Gas Well Pad MP
MP OGI Cost
Annual OGI
Semiannual OGI
Stepped OGI
HP Model Plant 2015
LP Model Plant 2015
Wellhead Model Plant 2015
Composition and Factors

Emissions (Production)

Oil well equipment counts obtained from Table W-1C of 40 CFR Part 98, Subpart W.
Gas well equipment and component counts based on total quantity of equipment for both Eastern & Western U.S. from the EPA/GI
Oil and Gas production TOC emission factors obtained from Table 2-4 from the EPA Equipment Leaks Protocol for components in ga
Model plant emissions for both oil and gas well pads based on 2 production wells per well site.

Emission Reduction Assumptions (Production)

OGI emission reductions assumed to be 40% for annual monitoring, 60% for semiannual monitoring and 60% for stepped monitorin

OGI Cost Assumptions (Production)

Labor costs obtained from Table 11 in the Memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, Analysis of Emission Reductio
Hours to read rule, develop monitoring plan and planning obtained from Attachment 7 in the Memorandum from Ken Meardon, PE
For production wells, the assumption of 22 well sites per natural gas production company was derived from the City of Fort Worth
OGI monitoring cost obtained from Appendix 1 in the Carbon Limits Report CL-13-27, Quantifying Cost-effectiveness of Systematic
The leak percentage (1.18%) was obtained from Table 5 for baseline gas valves from the memorandum from Cindy Hancy, RTI to Jo
The repair costs were estimated assuming 1.18% of the total components were found leaking per survey. 75% were assumed to be
The component resurvey cost based on estimates of resurvey costs assuming 5 minutes per leak at $57.80 per hour.

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Spreadsheet calculation of the model plant for natural gas production well pads. Includes calculations for equipment and compone
Spreadsheet calculation of the model plant for oil production well pads (GOR<300). Includes calculations for equipment and compc
Spreadsheet calculation of the model plant for oil production well pads (GOR>300). Includes calculations for equipment and compc
Spreadsheet calculation of the model plant for natural gas production well only. Includes calculations for component counts for a 2
Spreadsheet calculation of the model plant for oil production well only (GOR<300). Includes calculations for component counts for
Spreadsheet calculation of the model plant for oil production well only (GOR>300). Includes calculations for component counts for
Spreadsheet calculation of the model plant for low production wells (<15 barrels of oil equivalent per day). Includes calculations foı
Spreadsheet calculation of the model plant for low production (<15 BOED) oil well pads (GOR<300). Includes calculations for equipı
Spreadsheet calculation of the model plant for low production (<15 BOED) oil well pads (GOR>300). Includes calculations for equipı
Cost calculations for developing and implementing an OGI monitoring program at a natural gas and oil production well site.
Emission and cost per ton calculation summary for an annual OGI monitoring program at natural gas and oil production well pad m
Emission and cost per ton calculation summary for an semiannual OGI monitoring program at natural gas and oil production well pa
Emission and cost per ton calculation summary for a stepped OGI monitoring program at natural gas and oil production well pad m
Summary of the OGI monitoring options for high production model plants. Includes annual, semiannual and stepped monitoring fre
Summary of the OGI monitoring options for low production (<15 BOED) model plants. Includes annual, semiannual and stepped mc
Summary of reductions and costs associated with annual OGI monitoring for wells only, including the weighted cost per ton.
Natural gas composition values used to calculate methane, VOC and HAP emissions.

ns from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h).

ptions based on the Initial Economic Impact Analysis for proposed revisions to Colorado AQCC Regulation Number 7.

quipment Leaks, December 21, 2011 for general and operations managers.
EPA, Equipment Leak Analysis for Amino and Phenolic Resins NESHAP.
lity Study, July 2011.
Repair Programs Using Infrared Cameras. Assumed to be $600 for a single well battery.
alysis of Emission Reductions Techniques for Equipment Leaks, December 21, 2011.
ng 0.17 hours per repair at $66.24/hr. 25% were assumed to be repaired offline using 4.0 hours per repair at $66.24/hr.

Model Plant for Gas Well Pad

Equipment	*Model Plant (GRI)* [1]	*Rounded Model Plant (GRI)* [1]	*Updated GHGI Counts* [2]	*Rounded GHGI Counts*
Gas Wellheads	2.00	2.0	2.00	2.0
Seperators	1.56	2.0	1.37	2.0
Meter/Piping	0.83	1.0	1.71	2.0
In-Line Heaters	0.82	1.0	0.41	1.0
Dehydrators	0.55	1.0	0.05	1.0

[1] Estimated by rounding up the average equipment count per gas well from the EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

[2] Based on 2015 GHGI equipment counts for gas wells

Component Counts for Model Plant Equipment for Gas Well Pad

Components	*Model Plant (GRI)* [1]	*Rounded Model Plant (GRI)* [1]	*Updated GHGI Counts*	*Rounded GHGI Counts*
Valves	89	114	78	127
Connectors	324	414	282	462
Open-Ended Lines	11	14	9	14
Pressure Relief Valves	5	6	4	7

[1] Estimated using GRI model plant equipment count and average components per equipment

Estimated Component Counts per Equipment at Natural Gas Production Sites

	Average Component Count per Equipment[1]				Average Component Count per Model Plant			
Equipment	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves
Gas Wellheads	9.5	37.0	0.7	0.0	18.9	74.0	1.5	0.0
Separators	21.6	68.5	3.7	1.2	43.2	136.9	7.5	2.5
Meters/Piping	12.9	47.8	0.5	0.5	25.9	95.6	0.9	0.9
Gathering Compressors	71.1	175.1	2.9	3.9				
In-Line Heaters	14.0	65.0	2.0	1.0	14.0	65.0	2.0	1.0
Dehydrators	24.0	90.0	2.0	2.0	24.0	90.0	2.0	2.0

[1] Calculated by summing the total quantity of equipment and dividing by the total number of sites for both Eastern & Western U.S.
EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

GRI Equipment Counts					
Equipment	**Eastern US**	**Western US**	**Average**	**Avg/Well**	**GHGI**
Gas Wells	192	184	188	----	----
Heaters	77	77	77	0.41	0.21
Separators	110	183	147	0.78	0.69
Dehydrators	52	52	52	0.28	0.03
Meters/Piping	83	73	78	0.41	0.86

[1] Equipment counts obtained from EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 19
3.5 Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems

Model Plant for Oil Well Pad

Equipment	*GHGI Average Equipment per Well* [1]	*Updated GHGI Counts*	*Rounded GHGI Counts*
Oil Wellheads		2.00	2.0
Seperators	0.36	0.72	1.0
Headers	0.18	0.36	1.0
Heater/Treaters	0.23	0.47	1.0

[1] Based on 2015 GHGI equipment counts for light crude production.

Component Counts for Model Plant Equipment for Oil Well Pad

Componets	*Updated GHGI Counts*	*Rounded GHGI Counts*
Valves	20	29
Flanges	38	54
Connectors	26	42
Open-Ended Lines	0	0
Pressure Relief Valves	2	2

[1] Based on GHG equipment counts and component counts from Table W-1C of 40 CFR Part 98, Subpart W.

Estimated Component Counts per Equipment at Oil & Gas Production Sites

	Average Component Count per Equipment[1]					Average Component Count per Model Plant				
Equipment	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**
Wellheads	5	10	4	0	1	10.0	20.0	8.0	0.0	2.0
Seperators	6	12	10	0	0	6.0	12.0	10.0	0.0	0.0
Headers	5	10	4	0	0	5.0	10.0	4.0	0.0	0.0
Heater/Treaters	8	12	20	0	0	8.0	12.0	20.0	0.0	0.0

[1] Component counts obtained from Table W-1C of 40 CFR Part 98, Subpart W.

Model Plant for Oil w/ Associated Gas Well Pad

Equipment	*GHGI Average Equipment per Well*	*GHGI Equipment Counts*	*Rounded GHGI Equipment Counts*
Wellheads		2.00	2
Seperators (Light Crude)	0.36	0.72	1
Headers (Light Crude)	0.18	0.36	1
Heater/Treaters (Light Crude)	0.23	0.47	1
Meters/Piping (Natural Gas)	0.62	1.23	2

[1] Based on 2015 GHGI equipment counts for light crude production and meters/piping for natural gas.

Component Counts for Model Plant Equipment for Oil w/ Associated Gas Well Pad

Componets	*Rounded Model Plant (GHG)* [1]
Valves	55
Flanges	54
Connectors	138
Open-Ended Lines	1
Pressure Relief Valves	3

[1] Estimated using GHG model plant equipment count and GHGI/GRI average components per equipment

Estimated Component Counts per Equipment at Oil & Gas Production Sites

Equipment	Average Component Count per Equipment[1]				
	Valves	Flanges	Connectors & Flanges	Open-Ended Lines	Pressure Relief Valves
Wellheads	5	10	4	0	1
Seperators	6	12	10	0	0
Headers	5	10	4	0	0
Heater/Treaters	8	12	20	0	0

[1] Component counts obtained from Table W-1C of 40 CFR Part 98, Subpart W.

Estimated Component Counts per Equipment at Natural Gas Production Sites

Equipment	Average Component Count per Equipment[1]				Average Component Count per Model Plant				
	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Connectors	Open-Ended Lines	Pressure Relief Valves	Flanges[3]
Gas Wellheads[2]	9.5	37.0	0.7	0.0	10	8	0	2	20
Separators[2]	21.6	68.5	3.7	1.2	6	10	0	0	12
Meters/Piping	12.9	47.8	0.5	0.5	26	96	1	1	
Heaters/Treaters[2]					8	20	0	0	12
Headers[2]					5	4	0	0	10
Gathering Compressors	71.1	175.1	2.9	3.9					
In-Line Heaters	14.0	65.0	2.0	1.0					
Dehydrators	24.0	90.0	2.0	2.0					

[1] Calculated by summing the total quantity of equipment and dividing by the total number of sites for both Eastern & Western U.S.

EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

[2] Component counts in average component count per model plant is from Table W-1C of 40 CFR Part 98, Subpart W.

[3] Average component counts for flanges used in average coponent count per model plant is from Table W-1C of 40 CFR Part 98, Subpart W.

Model Plant for Gas Well Pad

Equipment	*Model Plant (GRI)* [1]	*Rounded Model Plant (GRI)* [1]	*Updated GHGI Counts* [2]	*Rounded GHGI Counts*
Gas Wellheads	2.00	2.0	2.00	2.0

Component Counts for Model Plant Equipment for Gas Well Pad

Componets	*Rounded GHGI Counts*
Valves	19
Connectors	75
Open-Ended Lines	2
Pressure Relief Valves	0

Estimated Component Counts per Equipment at Natural Gas Production Sites

	Average Component Count per Equipment[1]			
Equipment	**Valves**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**
Gas Wellheads	9.5	37.0	0.7	0.0
Separators	21.6	68.5	3.7	1.2
Meters/Piping	12.9	47.8	0.5	0.5
Gathering Compressors	71.1	175.1	2.9	3.9
In-Line Heaters	14.0	65.0	2.0	1.0
Dehydrators	24.0	90.0	2.0	2.0

[1] Calculated by summing the total quantity of equipment and dividing by the total number of sites for b
EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4

GRI Equipment Counts					
Equipment	**Eastern US**	**Western US**	**Average**	**Avg/Well**	**GHGI**
Gas Wells	192	184	188	----	----
Heaters	77	77	77	0.41	0.21
Separators	110	183	147	0.78	0.69
Dehydrators	52	52	52	0.28	0.03
Meters/Piping	83	73	78	0.41	0.86

[1] Equipment counts obtained from EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 3.5 Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems

Model Plant for Oil Well Pad

Equipment	*GHGI Average Equipment per Well* [1]	*Updated GHGI Counts*	*Rounded GHGI Counts*
Oil Wellheads		2.00	2.0

Component Counts for Model Plant Equipment for Oil Well Pad

Componets	*Rounded GHGI Counts*
Valves	10
Flanges	20
Connectors	8
Open-Ended Lines	0
Pressure Relief Valves	2

[1] Based on GHG equipment counts and component counts from Table W-1C of 40 CFR Part 98, Subpart W.

Estimated Component Counts per Equipment at Oil & Gas Production Sites

	Average Component Count per Equipment[1]				
Equipment	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**
Wellheads	5	10	4	0	1
Seperators	6	12	10	0	0
Headers	5	10	4	0	0
Heater/Treaters	8	12	20	0	0

[1] Component counts obtained from Table W-1C of 40 CFR Part 98, Subpart W.

Model Plant for Oil w/ Associated Gas Well Pad

Equipment	*GHGI Average Equipment per Well*	*GHGI Equipment Counts*	*Rounded GHGI Equipment Counts*
Wellheads		2.00	2

Component Counts for Model Plant Equipment for Oil w/ Associated Gas Well Pad

Componets	*Rounded Model Plant (GHG)* [1]
Valves	10
Flanges	20
Connectors	8
Open-Ended Lines	0
Pressure Relief Valves	2

[1] Estimated using GHG model plant equipment count and GHGI/GRI average components per equipment

Estimated Component Counts per Equipment at Oil & Gas Production Sites

Equipment	Average Component Count per Equipment[1]				
	Valves	Flanges	Connectors & Flanges	Open-Ended Lines	Pressure Relief Valves
Wellheads	5	10	4	0	1
Seperators	6	12	10	0	0
Headers	5	10	4	0	0
Heater/Treaters	8	12	20	0	0

[1] Component counts obtained from Table W-1C of 40 CFR Part 98, Subpart W.

Model Plant for Gas Well Pad		
Equipment	*FW Study Counts* [1]	*Rounded FW Counts* [2]
Gas Wellheads	1.64	2.0
Seperators	1.12	2.0
Meter/Piping	0.01	1.0
In-Line Heaters	0.00	0.0
Dehydrators	0.08	1.0

[1] Equipment counts obtained from the City of Fort Worth Natural Gas Air Quality Study, Final Report, Emissions Calculations Workbook, July 2011.
[2] Estimated by rounding up the average equipment count per low production gas well from the City of Fort Worth Natural Gas Air Quality Study, Fir

Component Counts for Model Plant Equipment for Gas Well Pad			
Components	*Updated FW Study Counts*	*Rounded FW Study Counts*	**Scaling Factor**
Valves	42	100	**0.787**
Connectors	145	349	**0.755**
Open-Ended Lines	6	12	**0.857**
Pressure Relief Valves	2	5	**0.714**

[1] Estimated using equipment counts from the City of Fort Worth Natural Gas Air Quality Study, July 2011 and average components per equipment a

Estimated Component Counts per Equipment at Natural Gas Production Sites

	Average Component Count per Equipment[1]				Average Component Count per Model Plant			
Equipment	**Valves**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Valves**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**
Gas Wellheads	9.5	37.0	0.7	0.0	18.9	74.0	1.5	0.0
Separators	21.6	68.5	3.7	1.2	43.2	136.9	7.5	2.5
Meters/Piping	12.9	47.8	0.5	0.5	12.9	47.8	0.5	0.5
Gathering Compressors	71.1	175.1	2.9	3.9				
In-Line Heaters	14.0	65.0	2.0	1.0	0.0	0.0	0.0	0.0
Dehydrators	24.0	90.0	2.0	2.0	24.0	90.0	2.0	2.0

[1] Calculated by summing the total quantity of equipment and dividing by the total number of sites for both Eastern & Western U.S.
EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

GRI Equipment Counts					
Equipment	**Eastern US**	**Western US**	**Average**	**Avg/Well**	**GHGI**
Gas Wells	192	184	188	----	----
Heaters	77	77	77	0.41	0.21
Separators	110	183	147	0.78	0.69
Dehydrators	52	52	52	0.28	0.03
Meters/Piping	83	73	78	0.41	0.86

[1] Equipment counts obtained from EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June
3.5 Methodology for Estimating CH4 and CO2 Emissions from Natural Gas Systems

Model Plant for Oil Well Pad			
Equipment	*GHGI Average Equipment per Well* [1]	*Updated GHGI Counts*	*Rounded GHGI Counts*
Oil Wellheads		2.00	2.0
Seperators	0.36	0.72	1.0
Headers	0.18	0.36	1.0
Heater/Treaters	0.23	0.47	1.0

[1] Based on 2015 GHGI equipment counts for light crude production.

Component Counts for Model Plant Equipment for Oil Well Pad	
Components	*Rounded Scaled Counts*
Valves	23
Flanges	41
Connectors	32
Open-Ended Lines	0
Pressure Relief Valves	2

[1] Based on GHG equipment counts and component counts from Table W-1C of 40 CFR Part 98, Subpart W.

Estimated Component Counts per Equipment at Oil & Gas Production Sites

	Average Component Count per Equipment[1]					Average Component Count per Model Plant				
Equipment	Valves	Flanges	Connectors	Open-Ended Lines	Pressure Relief Valves	Valves	Flanges	Connectors	Open-Ended Lines	Pressure Relief Valves
Wellheads	5	10	4	0	1	8	15	6	0	1
Seperators	6	12	10	0	0	5	9	8	0	0
Headers	5	10	4	0	0	4	8	3	0	0
Heater/Treaters	8	12	20	0	0	6	9	15	0	0

[1] Component counts obtained from Table W-1C of 40 CFR Part 98, Subpart W.

Model Plant for Oil w/ Associated Gas Well Pad

Equipment	*GHGI Average Equipment per Well*	*GHGI Equipment Counts*	*Rounded GHGI Equipment Counts*
Wellheads		2.00	2
Seperators (Light Crude)	0.36	0.72	1
Headers (Light Crude)	0.18	0.36	1
Heater/Treaters (Light Crude)	0.23	0.47	1
Meters/Piping (Natural Gas)	0.62	1.23	2

[1] Based on 2015 GHGI equipment counts for light crude production and meters/piping for natural gas.

Component Counts for Model Plant Equipment for Oil w/ Associated Gas Well Pad

Components	*Rounded Model Plant (GHG)* [1]
Valves	44
Flanges	41
Connectors	105
Open-Ended Lines	1
Pressure Relief Valves	3

[1] Estimated using GHG model plant equipment count and GHGI/GRI average components per equipment

Estimated Component Counts per Equipment at Oil & Gas Production Sites

	Average Component Count per Equipment[1]				
Equipment	**Valves**	**Flanges**	**Connectors & Flanges**	**Open-Ended Lines**	**Pressure Relief Valves**
Wellheads	5	10	4	0	1
Seperators	6	12	10	0	0
Headers	5	10	4	0	0
Heater/Treaters	8	12	20	0	0

[1] Component counts obtained from Table W-1C of 40 CFR Part 98, Subpart W.

Estimated Component Counts per Equipment at Natural Gas Production Sites

	Average Component Count per Equipment[1]				Average Component Count per Model Plant				
Equipment	**Valves**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Valves**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Flanges[3]**
Gas Wellheads[2]	9.5	37.0	0.7	0.0	8	6	0	1	15
Separators[2]	21.6	68.5	3.7	1.2	5	8	0	0	9
Meters/Piping	12.9	47.8	0.5	0.5	20	72	1	1	
Heaters/Treaters[2]					6	15	0	0	9
Headers[2]					4	3	0	0	8
Gathering Compressors	71.1	175.1	2.9	3.9					
In-Line Heaters	14.0	65.0	2.0	1.0					
Dehydrators	24.0	90.0	2.0	2.0					

[1] Calculated by summing the total quantity of equipment and dividing by the total number of sites for both Eastern & Western U.S.

EPA/GRI Methane Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h)

[2] Component counts in average component count per model plant is from Table W-1C of 40 CFR Part 98, Subpart W.

[3] Average component counts for flanges used in average coponent count per model plant is from Table W-1C of 40 CFR Part 98, Subpart W.

Cost Of Implementing OGI Monitoring Program at a Well Site

Item	Number of People	Number of Hours per Person	Total Hours	Labor Cost ($/hour)[a]	Biennial Contractor OGI ($/year)	Annual Contractor OGI ($/year)	Semiannual Contractor OGI ($/year)	Stepped Monitoring Contractor OGI ($/year)	Comment
Company Level Costs									
Read rule and instructions	1	4	4	$61.21	$245	$245	$245	$245	Hours from PES Memorandum[b] (Note: one time cost per company)
Development of Equipment Leaks Monitoring Plan	2.5	24	60	$61.21	$3,672	$3,672	$3,672	$3,672	Estimated cost to develop monitoring plan. Based on average number of people and hours from PES Memorandum[b] (Note: one time cost per company)
Initial Activities Planning	2	8	16	$61.21	$490	$979	$1,959	$1,224	Hours from PES Memorandum[b] assumed for each survey
Notification of Initial Compliance Status	1	1	1	$61.21	$1,347	$1,347	$1,347	$1,347	Assumes that 1 hour is spent to prepare the notification for each well site for 22 well sites
OGI Monitoring Device	N/A	N/A	N/A	N/A					OGI cost provided in API comments, 12/14/2015
OGI Operator Certification	N/A	N/A	N/A	N/A					Cost of certification from Infrared Training Center. FLIR recommends certification training every 5 years
M21 Monitoring Device	N/A	N/A	N/A	N/A					Assumes soap solution is used for resurvey when repairs are not possible during monitoring
First Year Total Hours and Cost per Company			*102*		*$5,753*	*$6,243*	*$7,222*	*$6,488*	Includes read rule and instructions, monitoring plan, intial activities planning, initial survey and notification of initial compliance status
First Year Total Hours and Cost per Well Site			*4.6*		*$262*	*$284*	*$328*	*$295*	Assumes company owns 22 well sites per district[c]
Well Site Level Costs									
Subsequent Activities Planning	2	8	16	$61.21	$22	$45	$89	$56	Hours from PES Memorandum[b]. Total cost of planning divided by total number of well sites per company
OGI Camera Survey	1	6.1	6.1	$61.21	$318	$635	$1,271	$794	Contractor assumed to be $600 per survey, adjusted for 2016$[d]
Repair Costs	N/A	N/A	N/A	N/A	$158	$316	$633	$395	Assumes 1.18% or 4 total leaks found per survey, 3 fixed online (3 * 0.17 hours *$66.24/hr) and 1 fixed offline (1 * 4.0 hours * $66.24/hr), adjusted for 2016$[e]
Repaired Component Resurvey (OGI/M21 Device)	N/A	N/A	N/A	N/A	$10	$20	$41	$26	Resurvey costs assumes 5 minutes per leak at $61.21 per hour, adjusted for 2016$
Travel to/from Well Pad	N/A	N/A	N/A	N/A					Based on API estimate of 15,000 total mile per basin, assumed 22 well pads per basin, and $0.54/mile (GSA)
Annual Report	1	4	4	$61.21	$245	$245	$245	$245	Assumes that 4 hours are spent to prepare the annual report for each well site and includes storing/filing of records
Annual Cost per Well Site					*$753*	*$1,261*	*$2,278*	*$1,516*	Sum of planning, monitoring, reporting and storing of records
Annual Cost with Amortized Capital Cost					*$797*	*$1,309*	*$2,333*	*$1,565*	First year cost per well site cost amortized over 8 years at 7% interest

[a] Costs obtained from Table 11 in the Memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, Analysis of Emission Reductions Techniques for Equipment Leaks, December 21, 2011 for general and operations managers.

[b] Hours obtained from Attachment 7 in the Memorandum from Ken Meardon, PES to John Schaefer, EPA, Equipment Leak Analysis for Amino and Phenolic Resins NESHAP

[c] The 22 well sites per natural gas production company district was derived from the City of Fort Worth Natural Gas Air Quality Study, July 2011.

[d] OGI monitoring cost obtained from Appendix 1 in the Carbon Limits Report CL-13-27, Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras

[e] The leak percentage was obtained from Table 5 of Memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, Analysis of Emission Reductions Techniques for Equipment Leaks, December 21, 2011.

[f] The component resurvey cost based on the average subsequent monitoring fee in Table 13 of Memorandum from Cindy Hancy, RTI to Jodi Howard, EPA, Analysis of Emission Reductions Techniques for Equipment Leaks, December 21, 2011.

[g] Cost values are based on adjusted for 2016$ using the GDP Deflator value os 1.058919 as updated by the Federal Reserve Economic Data on January 26, 2018.

1.058919 GDP Deflator

Average Model Plant Cost of Control for Well Pads w/o Recovery Credits - Biennial OGI Monitoring

Model Plant	Total Capital Investment[1]	Annual LDAR Cost ($/yr)[2]	Recovery Credits ($/yr)[3]	Annual LDAR Cost w/o Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions (Tons/yr)	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions (Tons/yr)	VOC Cost Effectiveness ($/Ton)	HAP Emissions (Tons/yr)	HAP Emission Reductions (Tons/yr)	HAP Cost Effectiveness ($/Ton)
Low Production Gas Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	4.80	-----	-----	1.335	-----	-----	0.0503	-----	-----
OGI Contractor Monitoring	$262	$797		$797	3.36	1.44	$553	0.935	0.401	$1,990	0.0352	0.0151	$52,814
Low Production Oil Well Site Model Plant													
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	1.83	-----	-----	0.508	-----	-----	0.0191	-----	-----
OGI Contractor Monitoring	$262	$797		$797	1.28	0.55	$1,453	0.356	0.152	$5,227	0.0134	0.0057	$138,740
Low Production Oil with Associated Gas Well Site Model Plant													
Baseline - Oil w/ Associated Gas	-----	-----	-----	-----	2.63	-----	-----	0.731	-----	-----	0.0276	-----	-----
OGI Contractor Monitoring	$262	$797		$797	1.84	0.79	$1,010	0.512	0.219	$3,632	0.0193	0.0083	$96,411

[1] Capital cost for contractor OGI includes cost for implementing the monitoring program divided between 22 well sites per company district.

[2] Annual cost for contractor OGI includes annual monitoring cost and amortization of capital cost over 8 years at 7% interest.

[3] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

Average Model Plant Cost of Control for Well Pads w/ Recovery Credits - Biennial OGI Monitoring

Model Plant	Total Capital Investment[1]	Annual LDAR Cost ($/yr)[2]	Recovery Credits ($/yr)[3]	Annual LDAR Cost w/ Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions (Tons/yr)	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions (Tons/yr)	VOC Cost Effectiveness ($/Ton)	HAP Emissions (Tons/yr)	HAP Emission Reductions (Tons/yr)	HAP Cost Effectiveness ($/Ton)
Low Production Gas Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	4.80	-----	-----	1.335	-----	-----	0.0503	-----	-----
OGI Contractor Monitoring	$262	$797	$286	$511	3.36	1.44	$355	0.935	0.401	$1,277	0.0352	0.0151	$52,814
Low Production Oil Well Site Model Plant													
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	1.83	-----	-----	0.508	-----	-----	0.0191	-----	-----
OGI Contractor Monitoring	$262	$797	$109	$688	1.28	0.55	$1,255	0.356	0.152	$4,514	0.0134	0.0057	$138,740
Low Production Oil with Associated Gas Well Site Model Plant													
Baseline - Oil w/ Associated Gas	-----	-----	-----	-----	2.63	-----	-----	0.731	-----	-----	0.0276	-----	-----
OGI Contractor Monitoring	$262	$797	$156	$640	1.84	0.79	$811	0.512	0.219	$2,919	0.0193	0.0083	$96,411

[1] Capital cost for contractor OGI includes cost for implementing the monitoring program divided between 22 well sites per company district.

[2] Annual cost for contractor OGI includes annual monitoring cost and amortization of capital cost over 8 years at 7% interest.

[3] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

Emission Reduction = 0.3

84	Natural gas Mscf/yr savings - Natural Gas Well Sites
32	Natural gas Mscf/yr savings - Oil Well Sites
46	Natural gas Mscf/yr savings - Associated Gas - Option 1

Well Pad Emission Summary

Model Plant

	Model Plant Component Count						Methane Emissions (Tons/yr)							VOC Emissions (Tons/yr)							HAP Emissions (Tons/yr)						
EF Source	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Thief Hatches**	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Thief Hatches**	**Total CH4 Emissions**	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Thief Hatches**	**Total VOC Emissions**	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Thief Hatches**	**Total HAP Emissions**
Gas Well Sites - GHGI	127	0	462	14	7	1	3.826	0.000	0.619	0.187	0.412	0.868	5.91	1.064	0.000	0.172	0.052	0.115	0.241	1.64	0.040	0.000	0.006	0.002	0.004	0.009	0.0619
Oil Well Sites - GHGI	29	54	42	0	2	1	0.874	0.141	0.056	0.000	0.118	0.868	2.06	0.243	0.039	0.016	0.000	0.033	0.241	0.57	0.009	0.001	0.001	0.000	0.001	0.009	0.0215
Oil Well w/ Associated Gas	55	54	138	1	3	1	1.657	0.141	0.185	0.013	0.177	0.868	3.04	0.461	0.039	0.051	0.004	0.049	0.241	0.85	0.017	0.001	0.002	0.000	0.002	0.009	0.0318
LP Gas Well Sites - GHGI	100	0	349	12	5	1	3.013	0.000	0.467	0.161	0.295	0.868	4.80	0.837	0.000	0.130	0.045	0.082	0.241	1.34	0.032	0.000	0.005	0.002	0.003	0.009	0.0503
LP Oil Well Sites - GHGI	23	41	32	0	2	1	0.693	0.107	0.043	0.000	0.118	0.868	1.83	0.193	0.030	0.012	0.000	0.033	0.241	0.51	0.007	0.001	0.000	0.000	0.001	0.009	0.0191
LP Oil Well w/ Associated Gas	44	41	105	1	3	1	1.326	0.107	0.141	0.013	0.177	0.868	2.63	0.368	0.030	0.039	0.004	0.049	0.241	0.73	0.014	0.001	0.001	0.000	0.002	0.009	0.0276

Equipment Leaks Protocol TOC Emission Factors[1]

	Uncontrolled (kg/hr/comp)
Valves	0.0045
Flanges	0.00039
Connectors	0.0002
OEL	0.002
PRV	0.0088
Thief Hatches[2]	0.1296

[1] TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service

[2] Thief hatch emission factors are based on information obtained from Lyon, D., et al. "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," Environ. Sci. Technol. 2016, 50, 4877-4886. We have used 1g/s for emissions from thief hatches and tank vents because the study represents this as the minimum detection limit for these sources which have emissions composed primarily of higher hydrocarbons.

Average Model Plant Cost of Control for Well Pads w/o Recovery Credits - Annual OGI Monitoring

Model Plant	Total Capital Investment[1]	Annual LDAR Cost ($/yr)[2]	Recovery Credits ($/yr)[3]	Annual LDAR Cost w/o Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions (Tons/yr)	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions (Tons/yr)	VOC Cost Effectiveness ($/Ton)	HAP Emissions (Tons/yr)	HAP Emission Reductions (Tons/yr)	HAP Cost Effectiveness ($/Ton)
Natural Gas Production Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	5.91	-----	-----	1.643	-----	-----	0.0619	-----	-----
OGI Contractor Monitoring	$284	$1,309		$1,309	3.55	2.36	$553	0.986	0.657	$1,991	0.0371	0.0248	$52,853
Oil Production Well Site Model Plant													
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	2.06	-----	-----	0.572	-----	-----	0.0215	-----	-----
OGI Contractor Monitoring	$284	$1,309		$1,309	1.23	0.82	$1,591	0.343	0.229	$5,725	0.0129	0.0086	$151,954
Oil Production with Associated Gas Well Site Model Plant													
Baseline - Oil w/ Associated Gas	-----	-----	-----	-----	3.04	-----	-----	0.845	-----	-----	0.0318	-----	-----
OGI Contractor Monitoring	$284	$1,309		$1,309	1.82	1.22	$1,076	0.507	0.338	$3,872	0.0191	0.0127	$102,770
Low Production Gas Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	4.80	-----	-----	1.335	-----	-----	0.0503	-----	-----
OGI Contractor Monitoring	$284	$1,309		$1,309	2.88	1.92	$681	0.801	0.534	$2,451	0.0302	0.0201	$65,060
Low Production Oil Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	1.83	-----	-----	0.508	-----	-----	0.0191	-----	-----
OGI Contractor Monitoring	$284	$1,309		$1,309	1.10	0.73	$1,790	0.305	0.203	$6,439	0.0115	0.0077	$170,911
Low Production Oil with Associated Gas Model Plant													
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	2.63	-----	-----	0.731	-----	-----	0.0276	-----	-----
OGI Contractor Monitoring	$284	$1,309		$1,309	1.58	1.05	$1,244	0.439	0.293	$4,474	0.0165	0.0110	$118,767
Non-Low Production Gas Well Only Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	0.70	-----	-----	0.194	-----	-----	0.0073	-----	-----
OGI Contractor Monitoring	$284	$1,309		$1,309	0.42	0.28	$4,677	0.117	0.078	$16,827	0.0044	0.0029	$446,643
Non-Low Production Oil Well Only Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	0.48	-----	-----	0.134	-----	-----	0.0050	-----	-----
OGI Contractor Monitoring	$284	$1,309		$1,309	0.29	0.19	$6,789	0.080	0.054	$24,422	0.0030	0.0020	$648,253
Non-Low Production Oil with Associated Gas Well Only Model Plant													
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	0.48	-----	-----	0.134	-----	-----	0.0050	-----	-----
OGI Contractor Monitoring	$284	$1,309		$1,309	0.29	0.19	$6,789	0.080	0.054	$24,422	0.0030	0.0020	$648,253

[1] Capital cost for contractor OGI includes cost for implementing the monitoring program divided between 22 well sites per company district.
[2] Annual cost for contractor OGI includes annual monitoring cost and amortization of capital cost over 8 years at 7% interest.
[3] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

Average Model Plant Cost of Control for Well Pads w/ Recovery Credits - Annual OGI Monitoring

Model Plant	Total Capital Investment[1]	Annual LDAR Cost ($/yr)[2]	Recovery Credits ($/yr)[3]	Annual LDAR Cost w/ Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions (Tons/yr)	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions (Tons/yr)	VOC Cost Effectiveness ($/Ton)	HAP Emissions (Tons/yr)	HAP Emission Reductions (Tons/yr)	HAP Cost Effectiveness ($/Ton)
Natural Gas Production Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	5.91	-----	-----	1.643	-----	-----	0.0619	-----	-----
OGI Contractor Monitoring	$284	$1,309	$469	$840	3.55	2.36	$355	0.986	0.657	$1,278	0.0371	0.0248	$33,927
Oil Production Well Site Model Plant													
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	2.06	-----	-----	0.572	-----	-----	0.0215	-----	-----
OGI Contractor Monitoring	$284	$1,309	$163	$1,146	1.23	0.82	$1,393	0.343	0.229	$5,012	0.0129	0.0086	$133,029
Oil Production with Associated Gas Well Site Model Plant													
Baseline - Oil w/ Associated Gas	-----	-----	-----	-----	3.04	-----	-----	0.845	-----	-----	0.0318	-----	-----
OGI Contractor Monitoring	$284	$1,309	$241	$1,068	1.82	1.22	$878	0.507	0.338	$3,159	0.0191	0.0127	$83,845
Low Production Gas Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	4.80	-----	-----	1.335	-----	-----	0.0503	-----	-----
OGI Contractor Monitoring	$284	$1,309	$381	$928	2.88	1.92	$483	0.801	0.534	$1,738	0.0302	0.0201	$46,135
Low Production Oil Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	1.83	-----	-----	0.731	-----	-----	0.0191	-----	-----
OGI Contractor Monitoring	$284	$1,309	$469	$840	1.10	0.73	$1,149	0.439	0.293	$2,872	0.0115	0.0077	$109,712
Low Production Oil with Associated Gas Model Plant													
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	2.63	-----	-----	0.731	-----	-----	0.0276	-----	-----
OGI Contractor Monitoring	$284	$1,309	$163	$1,146	1.58	1.05	$1,089	0.439	0.293	$3,917	0.0165	0.0110	$103,975

[1] Capital cost for contractor OGI includes cost for implementing the monitoring program divided between 22 well sites per company district.
[2] Annual cost for contractor OGI includes annual monitoring cost and amortization of capital cost over 8 years at 7% interest.
[3] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

Emission Reduction = 0.4

137	Natural gas Mscf/yr savings - Natural Gas Well Sites
48	Natural gas Mscf/yr savings - Oil Well Sites
70	Natural gas Mscf/yr savings - Associated Gas - Option 1

Well Pad Emission Summary

Model Plant

	Model Plant Component Count						Methane Emissions (Tons/yr)							VOC Emissions (Tons/yr)							HAP Emissions (Tons/yr)						
EF Source	Valves	Flanges	Connectors	Open-Ended Lines	Pressure Relief Valves	Thief Hatches	Valves	Flanges	Connectors	Open-Ended Lines	Pressure Relief Valves	Thief Hatches	Total CH4 Emissions	Valves	Flanges	Connectors	Open-Ended Lines	Pressure Relief Valves	Thief Hatches	Total VOC Emissions	Valves	Flanges	Connectors	Open-Ended Lines	Pressure Relief Valves	Thief Hatches	Total HAP Emissions
HP Gas Well Sites - GHGI	127	0	462	14	7	1	3.826	0.000	0.619	0.187	0.412	0.868	5.91	1.064	0.000	0.172	0.052	0.115	0.241	1.64	0.040	0.000	0.006	0.002	0.004	0.009	0.0619
HP Oil Well Sites - GHGI	29	54	42	0	2	1	0.874	0.141	0.056	0.000	0.118	0.868	2.06	0.243	0.039	0.016	0.000	0.033	0.241	0.57	0.009	0.001	0.001	0.000	0.001	0.009	0.0215
HP Oil Well w/ Associated Gas	55	54	138	1	3	1	1.657	0.141	0.185	0.013	0.177	0.868	3.04	0.461	0.039	0.051	0.004	0.049	0.241	0.85	0.017	0.001	0.002	0.000	0.002	0.009	0.0318
LP Gas Well Sites - GHGI	100	0	349	12	5	1	3.013	0.000	0.467	0.161	0.295	0.868	4.80	0.837	0.000	0.130	0.045	0.082	0.241	1.34	0.032	0.000	0.005	0.002	0.003	0.009	0.0503
LP Oil Well Sites - GHGI	23	41	32	0	2	1	0.693	0.107	0.043	0.000	0.118	0.868	1.83	0.193	0.030	0.012	0.000	0.033	0.241	0.51	0.007	0.001	0.000	0.000	0.001	0.009	0.0191
LP Oil Well w/ Associated Gas	44	41	105	1	3	1	1.326	0.107	0.141	0.013	0.177	0.868	2.63	0.368	0.030	0.039	0.004	0.049	0.241	0.73	0.014	0.001	0.001	0.000	0.002	0.009	0.0276
HP Gas WellOnly Sites	19	0	75	2	0	0	0.572	0.000	0.100	0.027	0.000	0.000	0.70	0.159	0.000	0.028	0.007	0.000	0.000	0.19	0.006	0.000	0.001	0.000	0.000	0.000	0.0073
HP Oil WellOnly Sites	10	20	8	0	2	0	0.301	0.052	0.011	0.000	0.118	0.000	0.48	0.084	0.015	0.003	0.000	0.033	0.000	0.13	0.003	0.001	0.000	0.000	0.001	0.000	0.0050
HP Oil WellOnly w/ Associated Gas	10	20	8	0	2	0	0.301	0.052	0.011	0.000	0.118	0.000	0.48	0.084	0.015	0.003	0.000	0.033	0.000	0.13	0.003	0.001	0.000	0.000	0.001	0.000	0.0050

Equipment Leaks Protocol TOC Emission Factors[1]

	Uncontrolled (kg/hr/comp)
Valves	0.0045
Flanges	0.00039
Connectors	0.0002
OEL	0.002
PRV	0.0088
Thief Hatches[2]	0.1296

[1] TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service
[2] Thief hatch emission factors are based on information obtained from Lyon, D., et al. "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," Environ. Sci. Technol. 2016, 50, 4877-4886. We have used 1g/s for emissions from thief hatches and tank vents because the study represents this as the minimum detection limit for these sources which have emissions composed primarily of higher hy

Average Model Plant Cost of Control for Well Pads w/o Recovery Credits - Semiannual OGI Monitoring

Model Plant	Total Capital Investment[1]	Annual LDAR Cost ($/yr)[2]	Recovery Credits ($/yr)[3]	Annual LDAR Cost w/o Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions (Tons/yr)	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions (Tons/yr)	VOC Cost Effectiveness ($/Ton)	HAP Emissions (Tons/yr)	HAP Emission Reductions (Tons/yr)	HAP Cost Effectiveness ($/Ton)
Natural Gas Production Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	5.91	-----	-----	1.643	-----	-----	0.0619	-----	-----
OGI Contractor Monitoring	$328	$2,333		$2,333	2.36	3.55	$658	0.657	0.986	$2,366	0.0248	0.0371	$62,801
Oil Production Well Site Model Plant													
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	2.06	-----	-----	0.572	-----	-----	0.0215	-----	-----
OGI Contractor Monitoring	$328	$2,333		$2,333	0.82	1.23	$1,891	0.229	0.343	$6,802	0.0086	0.0129	$180,557
Oil Production with Associated Gas Well Site Model Plant													
Baseline - Oil w/ Associated Gas	-----	-----	-----	-----	3.04	-----	-----	0.845	-----	-----	0.0318	-----	-----
OGI Contractor Monitoring	$328	$2,333		$2,333	1.22	1.82	$1,279	0.338	0.507	$4,601	0.0127	0.0191	$122,115
Low Production Gas Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	4.80	-----	-----	1.335	-----	-----	0.0503	-----	-----
OGI Contractor Monitoring	$328	$2,333		$2,333	1.92	2.88	$810	0.534	0.801	$2,912	0.0201	0.0302	$77,307
Low Production Oil Well Site Model Plant													
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	1.83	-----	-----	0.508	-----	-----	0.0191	-----	-----
OGI Contractor Monitoring	$328	$2,333		$2,333	0.73	1.10	$2,127	0.203	0.305	$7,651	0.0077	0.0115	$203,083
Low Production Oil with Associated Gas Well Site Model Plant													
Baseline - Oil w/ Associated Gas	-----	-----	-----	-----	2.63	-----	-----	0.731	-----	-----	0.0276	-----	-----
OGI Contractor Monitoring	$328	$2,333		$2,333	1.05	1.58	$1,478	0.293	0.439	$5,317	0.0110	0.0165	$141,123

[1] Capital cost for contractor OGI includes cost for implementing the monitoring program divided between 22 well sites per company district.
[2] Annual cost for contractor OGI includes annual monitoring cost and amortization of capital cost over 8 years at 7% interest.
[3] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

Average Model Plant Cost of Control for Well Pads w/ Recovery Credits - Semiannual OGI Monitoring

Model Plant	Total Capital Investment[1]	Annual LDAR Cost ($/yr)[2]	Recovery Credits ($/yr)[3]	Annual LDAR Cost w/ Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions (Tons/yr)	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions (Tons/yr)	VOC Cost Effectiveness ($/Ton)	HAP Emissions (Tons/yr)	HAP Emission Reductions (Tons/yr)	HAP Cost Effectiveness ($/Ton)
Natural Gas Production Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	5.91	-----	-----	1.643	-----	-----	0.0619	-----	-----
OGI Contractor Monitoring	$328	$2,333	$703	$1,630	2.36	3.55	$459	0.657	0.986	$1,653	0.0248	0.0371	$43,876
Oil Production Well Site Model Plant													
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	2.06	-----	-----	0.572	-----	-----	0.0215	-----	-----
OGI Contractor Monitoring	$328	$2,333	$245	$2,088	0.82	1.23	$1,693	0.229	0.343	$6,089	0.0086	0.0129	$161,632
Oil Production with Associated Gas Well Site Model Plant													
Baseline - Oil w/ Associated Gas	-----	-----	-----	-----	3.04	-----	-----	0.845	-----	-----	0.0318	-----	-----
OGI Contractor Monitoring	$328	$2,333	$362	$1,971	1.22	1.82	$1,081	0.338	0.507	$3,888	0.0127	0.0191	$103,190
Low Production Gas Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	4.80	-----	-----	1.335	-----	-----	0.0503	-----	-----
OGI Contractor Monitoring	$328	$2,333	$571	$1,762	1.92	2.88	$611	0.534	0.801	$2,199	0.0201	0.0302	$77,307
Low Production Oil Well Site Model Plant													
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	1.83	-----	-----	0.508	-----	-----	0.0191	-----	-----
OGI Contractor Monitoring	$328	$2,333	$217	$2,116	0.73	1.10	$1,929	0.203	0.305	$6,938	0.0077	0.0115	$203,083
Low Production Oil with Associated Gas Well Site Model Plant													
Baseline - Oil w/ Associated Gas	-----	-----	-----	-----	2.63	-----	-----	0.731	-----	-----	0.0276	-----	-----
OGI Contractor Monitoring	$328	$2,333	$313	$2,020	1.05	1.58	$1,280	0.293	0.439	$4,604	0.0110	0.0165	$141,123

[1] Capital cost for contractor OGI includes cost for implementing the monitoring program divided between 22 well sites per company district.
[2] Annual cost for contractor OGI includes annual monitoring cost and amortization of capital cost over 8 years at 7% interest.
[3] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

Emission Reduction = 0.6

206	Natural gas Mscf/yr savings - Natural Gas Well Sites
72	Natural gas Mscf/yr savings - Oil Well Sites
106	Natural gas Mscf/yr savings - Associated Gas - Option 1

Well Pad Emission Summary

Model Plant

	Model Plant Component Count						Methane Emissions (Tons/yr)							VOC Emissions (Tons/yr)							HAP Emissions (Tons/yr)						
EF Source	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Thief Hatches**	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Thief Hatches**	**Total CH4 Emissions**	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Thief Hatches**	**Total VOC Emissions**	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Thief Hatches**	**Total HAP Emissions**
Gas Well Sites - GHGI	127	0	462	14	7	1	3.826	0.000	0.619	0.187	0.412	0.868	5.91	1.064	0.000	0.172	0.052	0.115	0.241	1.64	0.040	0.000	0.006	0.002	0.004	0.009	0.0619
Oil Well Sites - GHGI	29	54	42	0	2	1	0.874	0.141	0.056	0.000	0.118	0.868	2.06	0.243	0.039	0.016	0.000	0.033	0.241	0.57	0.009	0.001	0.001	0.000	0.001	0.009	0.0215
Oil Well w/ Associated Gas	55	54	138	1	3	1	1.657	0.141	0.185	0.013	0.177	0.868	3.04	0.461	0.039	0.051	0.004	0.049	0.241	0.85	0.017	0.001	0.002	0.000	0.002	0.009	0.0318
LP Gas Well Sites - GHGI	100	0	349	12	5	1	3.013	0.000	0.467	0.161	0.295	0.868	4.80	0.837	0.000	0.130	0.045	0.082	0.241	1.34	0.032	0.000	0.005	0.002	0.003	0.009	0.0503
LP Oil Well Sites - GHGI	23	41	32	0	2	1	0.693	0.107	0.043	0.000	0.118	0.868	1.83	0.193	0.030	0.012	0.000	0.033	0.241	0.51	0.007	0.001	0.000	0.000	0.001	0.009	0.0191
LP Oil Well w/ Associated Gas	44	41	105	1	3	1	1.326	0.107	0.141	0.013	0.177	0.868	2.63	0.368	0.030	0.039	0.004	0.049	0.241	0.73	0.014	0.001	0.001	0.000	0.002	0.009	0.0276

Equipment Leaks Protocol TOC Emission Factors[1]

	Uncontrolled (kg/hr/comp)
Valves	0.0045
Flanges	0.00039
Connectors	0.0002
OEL	0.002
PRV	0.0088
Thief Hatches[2]	0.1296

[1] TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service
[2] Thief hatch emission factors are based on information obtained from Lyon, D., et al. "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," Environ. Sci. Technol. 2016, 50, 4877-4886. We have used 1g/s for emissions from thief hatches and tank vents because the study represents this as the minimum detection limit for these sources which have emissions composed primarily of higher hydrocarbons.

Average Model Plant Cost of Control for Well Pads w/o Recovery Credits - Stepped OGI Monitoring

Model Plant	Total Capital Investment[1]	Annual LDAR Cost ($/yr)[2]	Recovery Credits ($/yr)[3]	Annual LDAR Cost w/o Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions (Tons/yr)	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions (Tons/yr)	VOC Cost Effectiveness ($/Ton)	HAP Emissions (Tons/yr)	HAP Emission Reductions (Tons/yr)	HAP Cost Effectiveness ($/Ton)
Natural Gas Production Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	5.91	-----	-----	1.643	-----	-----	0.0619	-----	-----
OGI Contractor Monitoring	$295	$1,565		$1,565	3.25	2.66	$588	0.904	0.740	$2,116	0.0341	0.0279	$56,169
Oil Production Well Site Model Plant													
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	2.06	-----	-----	0.572	-----	-----	0.0215	-----	-----
OGI Contractor Monitoring	$295	$1,565		$1,565	1.13	0.93	$1,691	0.314	0.257	$6,084	0.0118	0.0097	$161,488
Oil Production with Associated Gas Well Site Model Plant													
Baseline - Oil w/ Associated Gas	-----	-----	-----	-----	3.04	-----	-----	0.845	-----	-----	0.0318	-----	-----
OGI Contractor Monitoring	$295	$1,565		$1,565	1.67	1.37	$1,144	0.465	0.380	$4,115	0.0175	0.0143	$109,219
Low Production Gas Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	4.80	-----	-----	1.335	-----	-----	0.0503	-----	-----
OGI Contractor Monitoring	$295	$1,565		$1,565	2.64	2.16	$724	0.734	0.601	$2,605	0.0277	0.0226	$69,142
Low Production Oil Well Site Model Plant													
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	1.83	-----	-----	0.508	-----	-----	0.0191	-----	-----
OGI Contractor Monitoring	$295	$1,565		$1,565	1.01	0.82	$1,902	0.280	0.229	$6,843	0.0105	0.0086	$181,635
Low Production Oil with Associated Gas Well Site Model Plant													
Baseline - Oil w/ Associated Gas	-----	-----	-----	-----	2.63	-----	-----	0.731	-----	-----	0.0276	-----	-----
OGI Contractor Monitoring	$295	$1,565		$1,565	1.45	1.18	$1,322	0.402	0.329	$4,755	0.0152	0.0124	$126,219

[1] Capital cost for contractor OGI includes cost for implementing the monitoring program divided between 22 well sites per company district.
[2] Annual cost for contractor OGI includes annual monitoring cost and amortization of capital cost over 8 years at 7% interest. 9.2621 0.00
[3] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf. 2.5746
0.0970

Average Model Plant Cost of Control for Well Pads w/ Recovery Credits - Stepped OGI Monitoring

Model Plant	Total Capital Investment[1]	Annual LDAR Cost ($/yr)[2]	Recovery Credits ($/yr)[3]	Annual LDAR Cost w/ Recovery Credits ($/yr)	Total CH4 Emissions (Tons/yr)	Total CH4 Emission Reductions (Tons/yr)	CH4 Cost Effectiveness ($/Ton)	Total VOC Emissions (Tons/yr)	Total VOC Emission Reductions (Tons/yr)	VOC Cost Effectiveness ($/Ton)	HAP Emissions (Tons/yr)	HAP Emission Reductions (Tons/yr)	HAP Cost Effectiveness ($/Ton)
Natural Gas Production Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	5.91	-----	-----	1.643	-----	-----	0.0619	-----	-----
OGI Contractor Monitoring	$295	$1,565	$527	$1,038	3.25	2.66	$390	0.904	0.740	$1,403	0.0341	0.0279	$37,243
Oil Production Well Site Model Plant													
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	2.06	-----	-----	0.572	-----	-----	0.0215	-----	-----
OGI Contractor Monitoring	$295	$1,565	$183	$1,382	1.13	0.93	$1,493	0.314	0.257	$5,371	0.0118	0.0097	$142,563
Oil Production with Associated Gas Well Site Model Plant													
Baseline - Oil w/ Associated Gas	-----	-----	-----	-----	3.04	-----	-----	0.845	-----	-----	0.0318	-----	-----
OGI Contractor Monitoring	$295	$1,565	$271	$1,294	1.67	1.37	$946	0.465	0.380	$3,402	0.0175	0.0143	$90,293
Low Production Gas Well Site Model Plant													
Baseline - Gas Well	-----	-----	-----	-----	4.80	-----	-----	1.335	-----	-----	0.0503	-----	-----
OGI Contractor Monitoring	$295	$1,565	$428	$1,137	2.64	2.16	$526	0.734	0.601	$1,892	0.0277	0.0226	$69,142
Low Production Oil Well Site Model Plant													
Baseline - Oil Well (GOR < 300)	-----	-----	-----	-----	1.83	-----	-----	0.508	-----	-----	0.0191	-----	-----
OGI Contractor Monitoring	$295	$1,565	$163	$1,402	1.01	0.82	$1,704	0.280	0.229	$6,130	0.0105	0.0086	$181,635
Low Production Oil with Associated Gas Well Site Model Plant													
Baseline - Oil w/ Associated Gas	-----	-----	-----	-----	2.63	-----	-----	0.731	-----	-----	0.0276	-----	-----
OGI Contractor Monitoring	$295	$1,565	$235	$1,330	1.45	1.18	$1,124	0.402	0.329	$4,042	0.0152	0.0124	$126,219

[1] Capital cost for contractor OGI includes cost for implementing the monitoring program divided between 22 well sites per company district.
[2] Annual cost for contractor OGI includes annual monitoring cost and amortization of capital cost over 8 years at 7% interest.
[3] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

Emission Reduction = 0.6

154	Natural gas Mscf/yr savings - Natural Gas Well Sites
54	Natural gas Mscf/yr savings - Oil Well Sites
79	Natural gas Mscf/yr savings - Associated Gas - Option 1

Well Pad Emission Summary

Model Plant

	Model Plant Component Count						Methane Emissions (Tons/yr)							VOC Emissions (Tons/yr)							HAP Emissions (Tons/yr)						
EF Source	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Thief Hatches**	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Thief Hatches**	**Total CH4 Emissions**	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Thief Hatches**	**Total VOC Emissions**	**Valves**	**Flanges**	**Connectors**	**Open-Ended Lines**	**Pressure Relief Valves**	**Thief Hatches**	**Total HAP Emissions**
Gas Well Sites - GHGI	127	0	462	14	7	1	3.826	0.000	0.619	0.187	0.412	0.868	5.91	1.064	0.000	0.172	0.052	0.115	0.241	1.64	0.040	0.000	0.006	0.002	0.004	0.009	0.0619
Oil Well Sites - GHGI	29	54	42	0	2	1	0.874	0.141	0.056	0.000	0.118	0.868	2.06	0.243	0.039	0.016	0.000	0.033	0.241	0.57	0.009	0.001	0.001	0.000	0.001	0.009	0.0215
Oil Well w/ Associated Gas	55	54	138	1	3	1	1.657	0.141	0.185	0.013	0.177	0.868	3.04	0.461	0.039	0.051	0.004	0.049	0.241	0.85	0.017	0.001	0.002	0.000	0.002	0.009	0.0318
LP Gas Well Sites - GHGI	100	0	349	12	5	1	3.013	0.000	0.467	0.161	0.295	0.868	4.80	0.837	0.000	0.130	0.045	0.082	0.241	1.34	0.032	0.000	0.005	0.002	0.003	0.009	0.0503
LP Oil Well Sites - GHGI	23	41	32	0	2	1	0.693	0.107	0.043	0.000	0.118	0.868	1.83	0.193	0.030	0.012	0.000	0.033	0.241	0.51	0.007	0.001	0.000	0.000	0.001	0.009	0.0191
LP Oil Well w/ Associated Gas	44	41	105	1	3	1	1.326	0.107	0.141	0.013	0.177	0.868	2.63	0.368	0.030	0.039	0.004	0.049	0.241	0.73	0.014	0.001	0.001	0.000	0.002	0.009	0.0276

Equipment Leaks Protocol TOC Emission Factors[1]

	Uncontrolled (kg/hr/comp)
Valves	0.0045
Flanges	0.00039
Connectors	0.0002
OEL	0.002
PRV	0.0088
Thief Hatches[2]	0.1296

[1] TOC emission factors obtained from Table 2-4 for the EPA Equipment Leaks Protocol for components in gas service
[2] Thief hatch emission factors are based on information obtained from Lyon, D., et al. "Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites," Environ. Sci. Technol. 2016, 50, 4877-4886. We have used 1g/s for emissions from thief hatches and tank vents because the study represents this as the minimum detection limit for these sources which have emissions composed primarily of higher hydrocarbons.

Model Plant 2015 - Single Pollutant

OGI Monitoring & Repair Plan - Oil & Natural Gas Production Well Sites

Category	Number of New Sources[1]	Model Plant Capital Cost ($)[2]	Model Plant Annual Cost ($/yr)[3]	Model Plant Annual Cost w/Savings ($/yr)[4]	Model Plant Emission Reductions[5]		Methane Cost of Control		VOC Cost of Control		Nationwide Emission Reductions		Total Nationwide Costs		
					Methane (Tons/yr)	VOC (Tons/yr)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	Methane (Tons/yr)	VOC (Tons/yr)	Capital Cost	Annual Cost w/o savings	Annual Cost w/ Savings
Stepped OGI Monitoring - Single Pollutant															
Gas Well Sites	2,001	$295	$1,565	$1,038	2.66	0.740	$588	$390	$2,116	$1,403	5,324	1,480	$590,094	$3,131,509	$2,076,386
Oil Well Sites (GOR < 300)	1,848	$295	$1,565	$1,382	0.93	0.257	$1,691	$1,493	$6,084	$5,371	1,710	475	$544,826	$2,891,285	$2,552,445
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$295	$1,565	$1,294	1.37	0.380	$1,144	$946	$4,115	$3,402	12,573	3,495	$2,709,977	$14,381,308	$11,889,315
All Wells Weighted Averages							**$1,041**	**$842**	**$3,744**	**$3,031**					
Annual OGI Monitoring - Single Pollutant															
Gas Well Sites	2,001	$284	$1,309	$840	2.36	0.657	$553	$355	$1,991	$1,278	4,732	1,315	$567,826	$2,619,220	$1,681,333
Oil Well Sites (GOR < 300)	1,848	$284	$1,309	$1,146	0.82	0.229	$1,591	$1,393	$5,725	$5,012	1,520	422	$524,267	$2,418,295	$2,117,104
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$284	$1,309	$1,068	1.22	0.338	$1,076	$878	$3,872	$3,159	11,176	3,107	$2,607,714	$12,028,647	$9,813,542
All Wells Weighted Averages							**$979**	**$781**	**$3,523**	**$2,810**					
Semi-Annual OGI Monitoring - Single Pollutant															
Gas Well Sites	2,001	$328	$2,333	$1,630	3.55	0.986	$658	$459	$2,366	$1,653	7,098	1,973	$656,897	$4,668,374	$3,261,543
Oil Well Sites (GOR < 300)	1,848	$328	$2,333	$2,088	1.23	0.343	$1,891	$1,693	$6,802	$6,089	2,279	634	$606,505	$4,310,255	$3,858,468
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$328	$2,333	$1,971	1.82	0.507	$1,279	$1,081	$4,601	$3,888	16,764	4,660	$3,016,767	$21,439,292	$18,116,634
All Wells Weighted Averages							**$1,164**	**$965**	**$4,186**	**$3,473**					

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR based on data from the HPDI.

[2] Capital cost includes costs for reading rule, developing monitoring plan, intial activities planning, and notification of initial compliance status.

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 years at 7% interest.

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

[5] Assumes 40% reduction with annual OGI camera monitoring, 60% reduction with semiannual OGI camera monitoring and 60% reduction with stepped OGI camera monitoring.

Model Plant 2015 - Multi Pollutant

OGI Monitoring & Repair Plan - Oil & Natural Gas Production Well Sites

Category	Number of New Sources[1]	Capital Cost ($)[2]	Annual Cost ($/yr)[3]	Well Site Annual Cost w/Savings ($/yr)[4]	Nationwide Emission Reductions[5]		Methane Cost of Control		VOC Cost of Control		Nationwide Emission Reductions		Total Nationwide Costs		
					Methane (Tons/yr)	VOC (Tons/yr)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	Methane (Tons/yr)	VOC (Tons/yr)	Capital Cost	Annual Cost w/o savings	Annual Cost w/ Savings
Stepped OGI Monitoring- Multi Pollutant															
Gas Well Sites	2,001	$295	$1,565	$1,038	2.66	0.740	$294	$195	$1,058	$702	5,324	1,480	$590,094	$3,131,509	$2,076,386
Oil Well Sites (GOR < 300)	1,848	$295	$1,565	$1,382	0.93	0.257	$846	$746	$3,042	$2,685	1,710	475	$544,826	$2,891,285	$2,552,445
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$295	$1,565	$1,294	1.37	0.380	$572	$473	$2,057	$1,701	12,573	3,495	$2,709,977	$14,381,308	$11,889,315
All Wells Weighted Averages							**$520**	**$421**	**$1,872**	**$1,515**					
Annual OGI Monitoring - Multi Pollutant															
Gas Well Sites	2,001	$284	$1,309	$840	2.36	0.657	$277	$178	$996	$639	4,732	1,315	$567,826	$2,619,220	$1,681,333
Oil Well Sites (GOR < 300)	1,848	$284	$1,309	$1,146	0.82	0.229	$796	$697	$2,862	$2,506	1,520	422	$524,267	$2,418,295	$2,117,104
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$284	$1,309	$1,068	1.22	0.338	$538	$439	$1,936	$1,579	11,176	3,107	$2,607,714	$12,028,647	$9,813,542
All Wells Weighted Averages							**$490**	**$391**	**$1,761**	**$1,405**					
Semi-Annual OGI Monitoring - Multi Pollutant															
Gas Well Sites	2,001	$328	$2,333	$1,630	3.55	0.986	$329	$230	$1,183	$826	7,098	1,973	$656,897	$4,668,374	$3,261,543
Oil Well Sites (GOR < 300)	1,848	$328	$2,333	$2,088	1.23	0.343	$945	$846	$3,401	$3,045	2,279	634	$606,505	$4,310,255	$3,858,468
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$328	$2,333	$1,971	1.82	0.507	$639	$540	$2,300	$1,944	16,764	4,660	$3,016,767	$21,439,292	$18,116,634
All Wells Weighted Averages							**$582**	**$483**	**$2,093**	**$1,736**					

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR based on data from the HPDI.

[2] Capital cost includes costs for reading rule, developing monitoring plan, intial activities planning, and notification of initial compliance status.

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 years at 7% interest.

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

[5] Assumes 40% reduction with annual OGI camera monitoring, 60% reduction with semiannual OGI camera monitoring and 60% reduction with stepped OGI camera monitoring.

Model Plant 2015 - Single Pollutant

OGI Monitoring & Repair Plan - Oil & Natural Gas Production Well Sites

Category	Number of New Sources[1]	Model Plant Capital Cost ($)[2]	Model Plant Annual Cost ($/yr)[3]	Model Plant Annual Cost w/Savings ($/yr)[4]	Model Plant Emission Reductions[5]		Methane Cost of Control		VOC Cost of Control		Nationwide Emission Reductions		Total Nationwide Costs		
					Methane (Tons/yr)	VOC (Tons/yr)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	Methane (Tons/yr)	VOC (Tons/yr)	Capital Cost	Annual Cost w/o savings	Annual Cost w/ Savings
Biennial OGI Monitoring - Single Pollutant															
Low Production Gas Well Sites	409	$262	$797	$511	1.44	0.401	$553	$355	$1,990	$1,277	589	164	$106,829	$325,543	$208,887
Low Production Oil Well Sites (GOR < 300)	2,171	$262	$797	$688	0.55	0.152	$1,453	$1,255	$5,227	$4,514	1,190	331	$567,617	$1,729,722	$1,493,771
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$262	$797	$640	0.79	0.219	$1,010	$811	$3,632	$2,919	965	268	$319,571	$973,840	$782,675
All Wells Weighted Averages							**$1,104**	**$906**	**$3,972**	**$3,259**					
Stepped OGI Monitoring - Single Pollutant															
Low Production Gas Well Sites	409	$295	$1,565	$1,137	2.16	0.601	$724	$526	$2,605	$1,892	883	245	$120,466	$639,291	$464,306
Low Production Oil Well Sites (GOR < 300)	2,171	$295	$1,565	$1,402	0.82	0.229	$1,902	$1,704	$6,843	$6,130	1,786	496	$640,079	$3,396,771	$3,042,846
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$295	$1,565	$1,330	1.18	0.329	$1,322	$1,124	$4,755	$4,042	1,447	402	$360,367	$1,912,396	$1,625,649
All Wells Weighted Averages							**$1,445**	**$1,247**	**$5,200**	**$4,487**					
Annual OGI Monitoring - Single Pollutant															
Low Production Gas Well Sites	409	$284	$1,309	$928	1.92	0.534	$681	$483	$2,451	$1,738	785	218	$115,920	$534,708	$379,167
Low Production Oil Well Sites (GOR < 300)	2,171	$284	$1,309	$1,146	0.73	0.203	$1,790	$1,567	$6,439	$5,637	1,587	441	$615,925	$2,841,088	$2,487,239
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$284	$1,309	$1,068	1.05	0.293	$1,244	$1,015	$4,474	$3,650	1,286	357	$346,768	$1,599,544	$1,304,984
All Wells Weighted Averages							**$1,360**	**$1,140**	**$4,893**	**$4,102**					
Semi-Annual OGI Monitoring - Single Pollutant															
Low Production Gas Well Sites	409	$328	$2,333	$1,762	2.88	0.801	$810	$611	$2,912	$2,199	1,177	327	$134,104	$953,039	$719,726
Low Production Oil Well Sites (GOR < 300)	2,171	$328	$2,333	$2,088	1.10	0.305	$2,127	$1,904	$7,651	$6,849	2,381	662	$712,541	$5,063,821	$4,533,047
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$328	$2,333	$1,971	1.58	0.439	$1,478	$1,249	$5,317	$4,493	1,929	536	$401,163	$2,850,951	$2,409,111
All Wells Weighted Averages							**$1,616**	**$1,396**	**$5,814**	**$5,023**					

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR based on data from the HPDI.

[2] Capital cost includes costs for reading rule, developing monitoring plan, intial activities planning, and notification of initial compliance status.

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 years at 7% interest.

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

[5] Assumes 40% reduction with annual OGI camera monitoring, 60% reduction with semiannual OGI camera monitoring and 60% reduction with stepped OGI camera monitoring.

Model Plant 2015 - Multi Pollutant

OGI Monitoring & Repair Plan - Oil & Natural Gas Production Well Sites

Category	Number of New Sources[1]	Capital Cost ($)[2]	Annual Cost ($/yr)[3]	Well Site Annual Cost w/Savings ($/yr)[4]	Nationwide Emission Reductions[5]		Methane Cost of Control		VOC Cost of Control		Nationwide Emission Reductions		Total Nationwide Costs		
					Methane (Tons/yr)	VOC (Tons/yr)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	Methane (Tons/yr)	VOC (Tons/yr)	Capital Cost	Annual Cost w/o savings	Annual Cost w/ Savings
Biennial OGI Monitoring - Single Pollutant															
Low Production Gas Well Sites	409	$262	$797	$511	1.44	0.401	$277	$177	$995	$638	589	164	$106,829	$325,543	$208,887
Low Production Oil Well Sites (GOR < 300)	2,171	$262	$797	$688	0.55	0.152	$726	$627	$2,613	$2,257	1,190	331	$567,617	$1,729,722	$1,493,771
Low Production Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$262	$797	$640	0.79	0.219	$505	$406	$1,816	$1,460	965	268	$319,571	$973,840	$782,675
All Wells Weighted Averages							**$552**	**$453**	**$1,986**	**$1,629**					
Stepped OGI Monitoring - Multi Pollutant															
Gas Well Sites	409	$295	$1,565	$1,137	2.16	0.601	$362	$263	$1,302	$946	883	245	$120,466	$639,291	$464,306
Oil Well Sites (GOR < 300)	2,171	$295	$1,565	$1,402	0.82	0.229	$951	$852	$3,421	$3,065	1,786	496	$640,079	$3,396,771	$3,042,846
Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$295	$1,565	$1,330	1.18	0.329	$661	$562	$2,378	$2,021	1,447	402	$360,367	$1,912,396	$1,625,649
All Wells Weighted Averages							**$723**	**$624**	**$2,600**	**$2,243**					
Annual OGI Monitoring - Multi Pollutant															
Gas Well Sites	409	$284	$1,309	$928	1.92	0.534	$341	$242	$1,226	$869	785	218	$115,920	$534,708	$379,167
Oil Well Sites (GOR < 300)	2,171	$284	$1,309	$1,146	0.73	0.203	$895	$783	$3,219	$2,819	1,587	441	$615,925	$2,841,088	$2,487,239
Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$284	$1,309	$1,068	1.05	0.293	$622	$507	$2,237	$1,825	1,286	357	$346,768	$1,599,544	$1,304,984
All Wells Weighted Averages							**$680**	**$570**	**$2,446**	**$2,051**					
Semi-Annual OGI Monitoring - Multi Pollutant															
Gas Well Sites	409	$328	$2,333	$1,762	2.88	0.801	$405	$306	$1,456	$1,100	1,177	327	$134,104	$953,039	$719,726
Oil Well Sites (GOR < 300)	2,171	$328	$2,333	$2,088	1.10	0.305	$1,063	$952	$3,826	$3,425	2,381	662	$712,541	$5,063,821	$4,533,047
Oil Well Sites w/ Associated Gas (GOR > 300)	1,222	$328	$2,333	$1,971	1.58	0.439	$739	$624	$2,658	$2,246	1,929	536	$401,163	$2,850,951	$2,409,111
All Wells Weighted Averages							**$808**	**$698**	**$2,907**	**$2,512**					

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR based on data from the HPDI.

[2] Capital cost includes costs for reading rule, developing monitoring plan, intial activities planning, and notification of initial compliance status.

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 years at 7% interest.

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

[5] Assumes 40% reduction with annual OGI camera monitoring, 60% reduction with semiannual OGI camera monitoring and 60% reduction with stepped OGI camera monitoring.

Model Plant 2015 - Single Pollutant

OGI Monitoring & Repair Plan - Oil & Natural Gas Production Well Sites

Category	Number of New Sources[1]	Model Plant Capital Cost ($)[2]	Model Plant Annual Cost ($/yr)[3]	Model Plant Annual Cost w/Savings ($/yr)[4]	Model Plant Emission Reductions[5]		Methane Cost of Control		VOC Cost of Control		Nationwide Emission Reductions		Total Nationwide Costs		
					Methane (Tons/yr)	VOC (Tons/yr)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	Methane (Tons/yr)	VOC (Tons/yr)	Capital Cost	Annual Cost w/o savings	Annual Cost w/ Savings
Annual OGI Monitoring - Single Pollutant															
Gas Well Sites	2,001	$284	$1,309	$840	0.28	0.078	$4,677	$3,003	$16,827	$10,802	560	156	$567,826	$2,619,220	$1,681,333
Oil Well Sites (GOR < 300)	1,848	$284	$1,309	$1,146	0.19	0.054	$6,789	$5,943	$24,422	$21,381	356	99	$524,267	$2,418,295	$2,117,104
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$284	$1,309	$1,068	0.19	0.054	$6,789	$5,539	$24,422	$19,925	1,772	493	$2,607,714	$12,028,647	$9,813,542
All Wells Weighted Averages							**$6,349**	**$5,064**	**$22,840**	**$18,217**					

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR based on data from the HPDI.

[2] Capital cost includes costs for reading rule, developing monitoring plan, intial activities planning, and notification of initial compliance status.

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 years at 7% interest.

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

[5] Assumes 40% reduction with annual OGI camera monitoring, 60% reduction with semiannual OGI camera monitoring and 60% reduction with stepped OGI camera monitoring.

Model Plant 2015 - Multi Pollutant

OGI Monitoring & Repair Plan - Oil & Natural Gas Production Well Sites

Category	Number of New Sources[1]	Capital Cost ($)[2]	Annual Cost ($/yr)[3]	Well Site Annual Cost w/Savings ($/yr)[4]	Nationwide Emission Reductions[5]		Methane Cost of Control		VOC Cost of Control		Nationwide Emission Reductions		Total Nationwide Costs		
					Methane (Tons/yr)	VOC (Tons/yr)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	w/o Savings ($/Ton)	w/ Savings ($/Ton)	Methane (Tons/yr)	VOC (Tons/yr)	Capital Cost	Annual Cost w/o savings	Annual Cost w/ Savings
Annual OGI Monitoring - Multi Pollutant															
Gas Well Sites	2,001	$284	$1,309	$840	0.28	0.078	$2,339	$1,501	$8,413	$5,401	560	156	$567,826	$2,619,220	$1,681,333
Oil Well Sites (GOR < 300)	1,848	$284	$1,309	$1,146	0.19	0.054	$3,394	$2,972	$12,211	$10,690	356	99	$524,267	$2,418,295	$2,117,104
Oil Well Sites w/ Associated Gas (GOR > 300)	9,190	$284	$1,309	$1,068	0.19	0.054	$3,394	$2,769	$12,211	$9,963	1,772	493	$2,607,714	$12,028,647	$9,813,542
All Wells Weighted Averages							**$3,174**	**$2,532**	**$11,420**	**$9,109**					

[1] It was estimated that 42.2% of the total oil wells were less than 300 GOR and 57.8% were greater than 300 GOR based on data from the HPDI.

[2] Capital cost includes costs for reading rule, developing monitoring plan, intial activities planning, and notification of initial compliance status.

[3] Annual cost includes contractor monitoring, planning, storing of records and amortization of capital cost over 8 years at 7% interest.

[4] Recovery credits calculated assuming the natural gas (82.9% methane) from the methane reduction has a value of $3.42/Mscf.

[5] Assumes 40% reduction with annual OGI camera monitoring, 60% reduction with semiannual OGI camera monitoring and 60% reduction with stepped OGI camera monitoring.

Conversion of volume methane to mass methane

0.02082	tons methane/1000 scf	41.63	lbs/1000 scf
		0.04163	lbs/scf

Weight Ratios to Use in Estimating Emissions

	Production	Transmission
Methane:TOC	0.694769295	0.907710347
VOC:TOC	0.193128289	0.025120601
HAP:TOC	0.007275976	0.000746124
VOC:Methane	0.277974703	0.027674689
HAP:Methane	0.010472507	0.000821985
BTEX:Methane	0.002796071	0.000321995
HAP:VOC	0.037674316	0.029701695
BTEX:VOC	0.010058724	0.011635011

Volume Ratios to Use in Estimating Natural Gas Savings

	Production	Transmission
Methane:Gas	82.9%	92.8%

Natural Gas Cost Used For Savings $3.42 /1000 ft3 natural gas

2015 Activity Data from GHGI

Total Active Gas Wells	421,893
Heaters	87,087
Separators	289,046
Dehydrators	11,235
Meters/Piping	361,753
Compressors	33,026
Chemical Injection Pumps	79,806
Total Oil Wells	586,896
Oil Wellheads (heavy crude)	41,376
Oil Wellheads (light crude)	545,520
Separators (heavy crude)	23,105
Separators (light crude)	210,281
Heater/Treaters (light crude)	137,378
Headers (heavy crude)	34,490
Headers (light crude)	106,922
Chemical Injection Pumps	53,281

Message

From: Cozzie, David [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=EE8C3582A39D4D81AC38F29A2B3ABB2D-DCOZZIE]
Sent: 2/21/2017 8:17:44 PM
To: Hambrick, Amy [Hambrick.Amy@epa.gov]
CC: Davis, Alison [Davis.Alison@epa.gov]
Subject: RE: draft response for your review////FW: Follow-up regarding GAO review of natural gas storage oversight (job code 101218)

I guess my opinion is that we don't need to be answering their research questions at this point. The direct question that GAO is asking is the bottom question:

Because we are in the early stages of our work, we are still designing our review. We may have more questions in the future, but at this junction it would be helpful to understand the extent of EPA's involvement in the new rule establishing minimum safety standards for underground natural gas storage facilities. To this end, I am wondering if you could help me understand if you or anyone else within EPA:

- Is likely to assist the Pipeline and Hazardous Materials Safety Administration with implementing the new Interim Final Rule (81 Fed. Reg. 91860-73 (amending 49 C.F.R. 191-192)) that establishes minimum safety standards for underground natural gas storage facilities?
    - If so, who?
    - If so, to what extent do you anticipate he/she/they will be involved?

I think our response is simply in the one paragraph you had, minus the Aliso Canyon Task Force:

Earlier this winter EPA participated in the OMB intra agency review on the Pipeline and Hazardous Materials Safety Administration new Interim Final Rule (81 Fed. Reg. 91860-73). During that review, EPA provided comments and feedback to the intra agency group. ~~Additionally, EPA has participated in the Aliso Canyon Natural Gas Leak Task Force providing consultation.~~ While EPA does not get involved in the implementation of other agency's rules, we do participate in cross agency reviews on subjects that may interact with or impact EPA activities.

From: Hambrick, Amy
Sent: Tuesday, February 21, 2017 12:43 PM
To: Cozzie, David <Cozzie.David@epa.gov>
Cc: Davis, Alison <Davis.Alison@epa.gov>
Subject: draft response for your review////FW: Follow-up regarding GAO review of natural gas storage oversight (job code 101218)

Please let me know if you are ok with this response to GAO and or please add your edits. (Hope to email back by COB today.) Thanks.

Hi Mary,

While EPA's air regulations do not cover natural gas storage beyond the "city gate" (in the distribution segment), our rules do regulate storage as long as it falls within the source category (i.e., production / processing / transmission and storage segments).

In 2016, EPA issued three final rules that together will curb emissions of methane, smog-forming volatile organic compounds and toxic air pollutants such as benzene from new, reconstructed and modified oil and gas sources, while providing greater certainty about Clean Air Act. More info here: https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry

(1) **Final Updates to New Source Performance Standards** curb emissions of greenhouse gases (in the form of limitations on methane) and volatile organic compounds from additional new, modified and reconstructed sources in the oil and gas industry. Note that in this rule EPA updated the definition of 'city gate' to the 'Local Distribution Company Custody Transfer Station' (below). Anything that is beyond the custody transfer station is in distribution and is outside the scope of the rule.

   Local distribution company (LDC) custody transfer station means a metering station where the LDC receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines. (81 FR 35935)

(2) **Final Source Determination Rule** clarifies EPA's air permitting rules as they apply to the oil and natural gas industry.
(3) **Federal Implementation Plan for EPA's Indian Country Minor New Source Review program for oil and gas production sources** will limit harmful emissions while streamlining the permitting process for the oil and natural gas production industry in Indian country.

Other EPA activities in this sector include our recently issued Control Techniques Guidelines for reducing smog-forming volatile organic compound emissions from existing oil and natural gas equipment and processes in certain states and areas with smog problems, the Greenhouse Gas Reporting Program, and volunteer programs such as the Natural Gas STAR: Methane Challenge Program.

Earlier this winter EPA participated in the OMB intra agency review on the Pipeline and Hazardous Materials Safety Administration new Interim Final Rule (81 Fed. Reg. 91860-73). During that review, EPA provided comments and feedback to the intra agency. Additionally, EPA has participated in the Aliso Canyon Natural Gas Leak Task Force providing consultation. While EPA does not get involved in the implementation of other agency's rules, we do participate in cross agency work groups to discuss shared interests.

Should you have additional questions, you may reach out to me and I can coordinate with the appropriate folks on my end.

Regards,

Amy

Amy Hambrick
U.S. Environmental Protection Agency
(919)541-0964

From: Terry, Sara
Sent: Friday, February 17, 2017 1:24 PM
To: Hambrick, Amy <Hambrick.Amy@epa.gov>
Cc: Jones, Mike <Jones.Mike@epa.gov>; Collins, JoLynn <Collins.Jolynn@epa.gov>; Vincent, Marc <Vincent.Marc@epa.gov>; Noonan, Jenny <Noonan.Jenny@epa.gov>; Cozzie, David <Cozzie.David@epa.gov>
Subject: RE: Follow-up regarding GAO review of natural gas storage oversight (job code 101218)

Amy,

Please respond directly to Mary, as needed, with a cc to the Mike, Jolynn, Marc (in the cc line) and I.

Thanks again for keeping us looped in.

Sara

From: Hambrick, Amy
Sent: Friday, February 17, 2017 10:39 AM
To: Terry, Sara <Terry.Sara@epa.gov>
Subject: FW: Follow-up regarding GAO review of natural gas storage oversight (job code 101218)

Sara, per mention.

Thank you,

Amy

From: Hambrick, Amy
Sent: Wednesday, February 15, 2017 5:27 PM
To: Cozzie, David <Cozzie.David@epa.gov>
Subject: FW: Follow-up regarding GAO review of natural gas storage oversight (job code 101218)

David-

I received the below email from GAO regarding their review of natural gas storage oversight with some questions for EPA on what our involvement may be for helping to implement PHMSA's rule for safety standards for underground natural gas storage facilities. I've highlighted points to note in their email. This seems like a hot button item that we should check in on prior to any response being sent and figure out who the response should come from (me?). As a reminder, on 11/7/2016, Marguerite sent out a quick turn around request about the GAO engagement notification asking if EPA should participate in the audit.

FYI our team's consistent response for any questions that has come up on underground storage in the distribution segment has been essentially that "underground storage is included in OOOOa as long as it falls with the source category (i.e., production / processing / transmission and storage segments). If it's located in the distribution segment – beyond the "city gate" – then it's excluded. For example, in reference to Aliso Canyon, which falls in the distribution segment, is not regulated by OOOOa. Furthermore, EPA updated the definition of 'city gate' in OOOOa to the 'Local Distribution Company Custody Transfer Station'. Anything that is beyond the custody transfer station is in distribution and thus outside the scope of OOOOa"

Please advise on how I should proceed. Thank you,

Amy

Amy Hambrick
U.S. Environmental Protection Agency
(919)541-0964

From: Koenen, Mary [mailto:KoenenM@gao.gov]
Sent: Wednesday, February 15, 2017 4:10 PM
To: Hambrick, Amy <Hambrick.Amy@epa.gov>
Cc: Carroll, Lee H <Carrolll@gao.gov>
Subject: FW: Follow-up regarding GAO review of natural gas storage oversight (job code 101218)

Ms. Hambrick,

I understand from Bob Trent's message below that you are likely the best contact within EPA to direct my questions to. Since we are interacting for the first time, I thought I would explain that my colleague Lee Carroll (copied above) and I are working on a new GAO review of federal oversight of natural gas storage facilities. Our current researchable objectives are to help our congressional clients understand:

1) What is known about federal efforts to prevent and contain leaks at natural gas storage facilities?
2) To what extent are relevant federal agencies following leading planning practices in preparing to implement regulations intended to prevent and contain leaks from natural gas storage facilities?

Because we are in the early stages of our work, we are still designing our review. We may have more questions in the future, but at this junction it would be helpful to understand the extent of EPA's involvement in the new rule establishing minimum safety standards for underground natural gas storage facilities. To this end, I am wondering if you could help me understand if you or anyone else within EPA:

- Is likely to assist the Pipeline and Hazardous Materials Safety Administration with implementing the new Interim Final Rule (81 Fed. Reg. 91860-73 (amending 49 C.F.R. 191-192)) that establishes minimum safety standards for underground natural gas storage facilities?
    - If so, who?
    - If so, to what extent do you anticipate he/she/they will be involved?

Thank you for whatever information you can provide on this topic. We really appreciate your help!

With best regards,
Mary

From: Trent, Bobbie [mailto:Trent.Bobbie@epa.gov]
Sent: Wednesday, February 15, 2017 3:56 PM
To: Koenen, Mary
Cc: Howard, MarkT; Anthony, Sherri
Subject: FW: Follow-up regarding GAO review of natural gas storage oversight (job code 101218)

Hi Mary:

We apologize for the delay, I am sharing the update info below from our Office of Air, please let me know if you have any additional questions, thanks.

Bob Trent

202-566-0983

Mary can work with Amy Hambrick who is the overall oil and gas EPA/OAQPS contact. Her team has segment specific contacts (e.g. leaks, tanks, pneumatics, etc.) that she can pull in as needed. She's Bruce's replacement who previously coordinated and shared EPA comments back with interagency coordination on the Pipeline interim effort.

Here's her info:

- *Amy Hambrick*
- *Office of Air Quality Planning and Standards/OAR*
- *Hambrick.amy@Epa.gov/ 919-541-0964*

From: Koenen, Mary [mailto:KoenenM@gao.gov]
Sent: Wednesday, February 15, 2017 3:05 PM
To: Trent, Bobbie <Trent.Bobbie@epa.gov>
Cc: Carroll, Lee H <Carrolll@gao.gov>
Subject: RE: Follow-up regarding GAO review of natural gas storage oversight (job code 101218)

Bob,

I hope this message sees you well! Just a quick note from me to follow up on the email below. Have you, by any chance, been able to determine if anyone within EPA (perhaps Bruce Moore's replacement in OAR?):

- Is likely to assist the Pipeline and Hazardous Materials Safety Administration with implementing the new Interim Final Rule (81 Fed. Reg. 91860-73 (amending 49 C.F.R. 191-192)) that establishes minimum safety standards for underground natural gas storage facilities?
    - If so, who?
    - If so, to what extent do you anticipate he/she/they will be involved?

Thank you for whatever information you can provide! Your responses will help us design our review.

With best regards,
Mary

From: Koenen, Mary
Sent: Wednesday, February 08, 2017 5:24 PM
To: Trent, Bobbie
Cc: Carroll, Lee H
Subject: Follow-up regarding GAO review of natural gas storage oversight (job code 101218)

Bob,

It was a pleasure speaking with you and your colleagues in December about GAO's review of federal oversight of natural gas storage facilities (job code 101218). We will surely have more questions as our review progresses that we can direct to relevant points of contact. However, for the time being, it would be helpful as we plan our review to understand if anyone within EPA (perhaps Bruce Moore's replacement in OAR?):

- Is likely to assist the Pipeline and Hazardous Materials Safety Administration with implementing the new Interim Final Rule (81 Fed. Reg. 91860-73 (amending 49 C.F.R. 191-192)) that establishes minimum safety standards for underground natural gas storage facilities?

- If so, who?
- If so, to what extent do you anticipate he/she/they will be involved?

Thank you for providing this additional information!

With best regards,
Mary

Mary Albert Koenen
Senior Analyst, Natural Resources & Environment
U.S. Government Accountability Office
441 G Street, NW
Washington, D.C. 20548
202-512-9373
koenenm@gao.gov

Message

From: Gunasekara, Mandy [Gunasekara.Mandy@epa.gov]
Sent: 8/23/2017 5:06:19 PM
To: Bolen, Brittany [bolen.brittany@epa.gov]; Fotouhi, David [fotouhi.david@epa.gov]
CC: Schwab, Justin [schwab.justin@epa.gov]; Ferguson, Lincoln [ferguson.lincoln@epa.gov]; Dominguez, Alexander [dominguez.alexander@epa.gov]; Dravis, Samantha [dravis.samantha@epa.gov]
Subject: RE: Methane
Attachments: Status Update TPs_Augustdocx.docx

Great - Lincoln see attached. Let me know if you need more (or any clarifications).

-----Original Message-----
From: Bolen, Brittany
Sent: Wednesday, August 23, 2017 12:59 PM
To: Fotouhi, David <fotouhi.david@epa.gov>
Cc: Schwab, Justin <schwab.justin@epa.gov>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Ferguson, Lincoln <ferguson.lincoln@epa.gov>; Dominguez, Alexander <dominguez.alexander@epa.gov>; Dravis, Samantha <dravis.samantha@epa.gov>
Subject: Re: Methane

For a high-level overview, this is fine by me, too. Thanks!

> On Aug 23, 2017, at 12:53 PM, Fotouhi, David <fotouhi.david@epa.gov> wrote:
>

Ex. 5 Attorney Client (AC)

> David Fotouhi
>
> Deputy General Counsel
> Office of General Counsel
> U.S. Environmental Protection Agency
> Tel: +1 202.564.1976
> fotouhi.david@epa.gov
>
> -----Original Message-----
> From: Schwab, Justin
> Sent: Wednesday, August 23, 2017 12:36 PM
> To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>
> Cc: Ferguson, Lincoln <ferguson.lincoln@epa.gov>; Dominguez, Alexander <dominguez.alexander@epa.gov>; Bolen, Brittany <bolen.brittany@epa.gov>; Fotouhi, David <fotouhi.david@epa.gov>
> Subject: Re: Methane
>

Ex. 5 Attorney Client (AC)

>
> Sent from my iPhone
>
>> On Aug 23, 2017, at 12:06 PM, Gunasekara, Mandy <Gunasekara.Mandy@epa.gov> wrote:
>>
>> Lincoln, see below and attached.
>> Brittany and Justin, can you do a quick review to see of any issues with information?
>>
>> Status Update: New Source Performance Standard for Oil and Gas (i.e. Methane Rule)
>>
>> * The DC Circuit vacated the short-term 90-day stay meant to delay June 3rd compliance requirements associated with the methane rule. Accordingly, the rule and those associated compliance requirements have been in effect since July.

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Message

From: Dravis, Samantha [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=ECE53F0610054E669D9DFFE0B3A842DF-DRAVIS, SAM]
Sent: 7/10/2017 4:32:41 PM
To: Gunasekara, Mandy [Gunasekara.Mandy@epa.gov]; Bolen, Brittany [bolen.brittany@epa.gov]
Subject: RE: EPA methane rule delay

Ex. 5 Deliberative Process (DP) Give me a min

From: Gunasekara, Mandy
Sent: Monday, July 10, 2017 12:28 PM
To: Dravis, Samantha <dravis.samantha@epa.gov>; Bolen, Brittany <bolen.brittany@epa.gov>
Subject: RE: EPA methane rule delay

Suggested response before sending to OPA. Please review.

Ex. 5 Deliberative Process (DP)

From: Dravis, Samantha
Sent: Monday, July 10, 2017 12:12 PM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Bolen, Brittany <bolen.brittany@epa.gov>
Subject: FW: EPA methane rule delay

Do we need to discuss? I think we need to respond.

From: Graham, Amy
Sent: Monday, July 10, 2017 11:15 AM
To: Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Bolen, Brittany <bolen.brittany@epa.gov>; Dravis, Samantha <dravis.samantha@epa.gov>; Fotouhi, David <fotouhi.david@epa.gov>
Cc: Bowman, Liz <Bowman.Liz@epa.gov>; Wilcox, Jahan <wilcox.jahan@epa.gov>; Ferguson, Lincoln <ferguson.lincoln@epa.gov>
Subject: FW: EPA methane rule delay

I am going to work on a statement Ex. 5 Deliberative Process (DP)
Ex. 5 Deliberative Process (DP) Working on a tight deadline so appreciate anything you can send as soon as possible.

From: Chris Knight [mailto:chris.knight@argusmedia.com]
Sent: Monday, July 10, 2017 11:06 AM
To: Press <Press@epa.gov>
Subject: EPA methane rule delay

EPA press,
I am writing a story about how EPA has been unable to give the oil and gas industry the administration's promised relief from methane regulations, in part because of missteps that some say could have been avoided. For example, EPA did not publish the 90-day stay until two days after a major June 3 leak detection deadline, forcing industry to comply. Also, EPA did not propose the two-year methane rule delay until June 16, nearly five months into the administration. As you know, EPA will be taking comment on the two year delay until August 9, meaning a final rule will not be ready for months.

Do you have any response? Was there a reason why EPA waited to take action related to the methane rule delay?

My deadline is 1 p.m. EST

Thanks,
Chris Knight
Argus Media
202-349-2876

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Message

From: Wehrum, Bill [Wehrum.Bill@epa.gov]
Sent: 9/18/2018 9:40:34 PM
To: DeLuca, Isabel [DeLuca.Isabel@epa.gov]; Gunasekara, Mandy [Gunasekara.Mandy@epa.gov]; Woods, Clint [woods.clint@epa.gov]; Dominguez, Alexander [dominguez.alexander@epa.gov]
Subject: RE: Press Question on oil and gas NSPS

Let's find some time tomorrow to discuss.

_____
Bill Wehrum
Assistant Administrator
Office of Air and Radiation
U.S. Environmental Protection Agency
(202) 564-7404

From: DeLuca, Isabel
Sent: Tuesday, September 18, 2018 3:57 PM
To: Wehrum, Bill <Wehrum.Bill@epa.gov>; Gunasekara, Mandy <Gunasekara.Mandy@epa.gov>; Woods, Clint <woods.clint@epa.gov>; Dominguez, Alexander <dominguez.alexander@epa.gov>
Subject: Press Question on oil and gas NSPS

Hi all,
We have some press questions from Jackie Toth at *Morning Consult* on the oil and gas NSPS technical proposal. She had originally asked for an interview, then followed up with more specific question for a written response. Rather than try to answer each question separately, we thought a statement might be best. Can you please take a look at the response below and let us know if you have suggestions/edits?

Many thanks,
Isabel

Incoming questions:

Ex. 5 Deliberative Process (DP)

Draft response:

Ex. 5 Deliberative Process (DP)

Isabel DeLuca
Office of Air and Radiation, US EPA
(202) 343-9247

Oil and Gas NSPS (i.e. Methane Rule)

- In 2012, EPA set a new source performance standard (NSPS) for natural gas wells that are hydraulically fractured. These standards controlled the emission of volatile organic compounds (VOCs) emitted during the production and processing phases.
- In May 2016, EPA expanded the oil and gas requirements setting up a new NSPS to separately control GHGs, which is often referred to as the "methane rule" or "OOOOa". This action expanded the scope of federal authority beyond production and processing to transmission and storage.
- In early 2017, EPA initiated a reconsideration and review of the 2016 rule, which has been divided into two packages: a technical package and policy package.
- *Technical Package*: In September 2018, EPA proposed targeted improvements to the 2016 rule for the oil and gas industry that streamline implementation, reduce duplicative EPA and state requirements, and significantly decrease unnecessary burdens on domestic energy producers.
    - EPA intends to reconsider certain technical aspects of the fugitive emissions requirements, including monitoring frequency, low production wells, and incorporating emerging technologies and state programs in the alternative means of emissions limitations.
    - EPA also intends to reconsider pneumatic pump standards at well sites and certification requirements of control devices.
    - This technical package is expected to save up to approximately $484 million in regulatory costs from 2019 – 2025 or $75 million annually.
- *Policy Package*: EPA is drafting a policy proposal assessing whether it makes sense to separately regulate methane when control is already effectively achieved in the original OOOO (VOCs only) standard.
    - Further, the industry has undertaken a sophisticated voluntary approach to controlling methane throughout its chain of operation.
    - EPA will also assess whether the entire oil and gas sector should be regulated as one source given significant differences between production/processing and storage/distribution or whether those should be split into separate sources.
    - If the source was split, it is not clear that the relative GHG emissions would be of a high enough threshold to trigger the "significant contribution" criteria that is the statutory prerequisite to setting a performance standard for a covered pollutant under Title I of the Clean Air Act.

Rules Related to the Oil and Gas Sector

1. **Withdrawal of 2016 Information Request for the Oil and Gas Industry.** March 2017, withdrew the 2016 information collection request (ICR) relieving over 15,000 owners and operators in the oil and gas industry of this unnecessary and costly reporting burden.

2. **Targeted Improvements to NSPS for Oil and Gas (i.e. Technical Package)**: September 2018, proposed targeted improvements package to streamline implementation of Methane Rule, reduce duplicative requirements, and decrease unnecessary burdens saving the oil and gas industry up to $75 million a year, or a total of $484 million for the 2019-2025 period.

3. **Compliance Relief from NSPS for Oil and Gas (i.e. Fugitive Emission Amendments)**: March 2018, finalized amendments to Methane Rule to address unworkable requirements related to the Alaska Northern Slope and timing of repairs.

4. **Proposed Repeal of Control Technique Guidelines (CTG):** March 2018, proposed withdrawal of the 2016 Control Techniques Guidelines saving up to $49 million a year or a total of $599 million from 2021 through 2035

5. **NESHAP Reconsideration:** October 2017, granted reconsideration of several issues raised by oil and gas industry related to the 2012 Oil and Gas NESHAP (National Emission Standard for Hazardous Air Pollutants) final rule.

6. **Proposed Permit Streamlining Amendments to Indian Country FIP:** April 2018, proposed amendments to the 2016 Indian Country FIP for Uintah and Ourary Indian Reservations that limits emissions of harmful air pollutants while preserving important, streamlined permitting processes.

RFS: DRAFT Final 2019 Renewable Volume Obligations (RVOs)

Proposed 2019 Renewable Volume Obligations: On June 26, 2018, EPA issued a proposed rule under the Renewable Fuel Standards (RFS) program that would set the minimum amount of renewable fuels that must be supplied to the market in calendar year 2019, as well as the biomass based diesel volume standard for calendar year 2020. Below are the proposed and current draft final RVOs:

Ex. 5 Deliberative Process (DP)

RFS: President Trump's E15/RIN Market Reform Announcement

Background: On October 9, President Trump directed EPA to undertake a single Clean Air Act rulemaking that would accomplish two objectives. First, the rule would modify EPA regulations to allow gasoline blended with up to 15 percent ethanol (E15) to take advantage of the 1-psi Reid Vapor Pressure (RVP) waiver that currently applies to E10 during the summer months. Second, the rule would change certain elements of the renewable identification number (RIN) compliance system under the RFS program, in order to improve how the RIN market functions.

General Talking Points:

Ex. 5 Deliberative Process (DP)

American Petroleum Institute (API)

API Background: API is comprised of more than 600 members include large integrated companies, as well as exploration and production, refining, marketing, pipeline, and marine businesses, and service and supply firms. In addition to their advocacy, API's certification programs verify manufacturers of production, drilling, and refinery equipment comply with industry and regulatory standards.

Meeting Attendees: Mike Sommers, CEO

Relevant Background: May 2018, API announced Mike Sommers would replace outgoing President and CEO, Jack Gerard, effective September 1, 2018. Sommers most recently led the American Investment Council (ACI), formerly the Private Equity Growth Capital Council. ACI is a trade association founded in 2007 by a consortium of private equity firms including The BlackStone Group, The Carlyle Group, Madison Dearborn, Silver Lake Partners, among others.

Sommers spent two decades in the U.S. House of Representatives and the White House, including as chief of staff for Speaker of the House John A. Boehner (R-Ohio) and Special Assistant to President George W. Bush at the National Economic Council.

Sommers a graduate of Miami University and his wife, Jill Sommers, served two terms as a commissioner of the Commodity Futures and Trading Commission (2002-2009; 2009-2012).

Potential Topics of Discussion: Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

NEW POLL SHOWS MAJORITY OF VOTERS ARE CONCERNED ABOUT EXPANDING THE SALE OF E15 GASOLINE

202.682.8114 | press@api.org

WASHINGTON, October 29, 2018 – Today the American Petroleum Institute released the results of a new national poll conducted by Harris Poll, showing that the vast majority of voters are concerned about the Trump administration's proposal to allow the year-round sale of higher ethanol blended E15 gasoline.

"Consumers are speaking loud and clear," said API Vice President of Downstream and Industry Operations Frank Macchiarola. "These numbers reinforce the need for the administration to reconsider this decision to allow year-round sale of E15. Voters understand that allowing sale of a fuel that is not designed for nearly 75 percent of cars on the road today puts consumers at risk. American families should not have to be burdened with an unexpected car repair bill because of a fuel that our government essentially pushed into the marketplace against the clear letter of the law.

"E15 is symptom of the broken Renewable Fuel Standard and it's time for real reform. There is bipartisan agreement that the RFS is a failure and we urge the administration to support consensus legislation to significantly reform the RFS for the benefit of all consumers."

Key poll results:

- 79 percent of voters are concerned about expanded E15 sales and vehicle incompatibility.
- 83 percent of voters are concerned that consumers could shoulder higher pump prices if service stations are forced to invest in new infrastructure to accommodate certain types of fuels.
- 68 percent of voters are concerned about consumers mistakenly using E15 and causing damage to their engines.
- 81 percent of voters are concerned that government requirements could exceed the 10 percent level of ethanol in the nation's fuel supply which studies have shown could increase gasoline prices by up to 26 cents per gallon.

The poll results are posted on the API website.

Methodology

The study was conducted on October 12-16, 2018, by telephone by Harris Poll on behalf of the American Petroleum Institute among 1001 registered voters across the U.S., with a sampling error of +/- 3.1 percent. A full methodology is available upon request.

Rule Related to Oil and Gas Sector:

1. **Withdrawal of 2016 Information Request for the Oil and Gas Industry.** March 2017 withdrew the 2016 information collection request (ICR) relieving over 15,000 owners and operators in the oil and gas industry of this unnecessary and costly reporting burden.
2. **Targeted Improvements to NSPS for Oil and Gas (i.e. Technical Package)**: September 2018 proposed targeted improvements package to streamline implementation of Methane Rule, reduce duplicative requirements, and decrease unnecessary burdens saving the oil and gas industry up to $75 million a year, or a total of $484 million for the 2019-2025 period.
3. **Compliance Relief from NSPS for Oil and Gas (i.e. Fugitive Emission Amendments)**: March 2018 finalized amendments to Methane Rule to address unworkable requirements related to the Alaska Northern Slope and timing of repairs.
4. **Proposed Repeal of Control Technique Guidelines (CTG):** March 2018 proposed withdrawal of the 2016 Control Techniques Guidelines saving up to $49 million a year or a total of $599 million from 2021 through 2035
5. **NESHAP Reconsideration:** October 2017, granted reconsideration of several issues raised by oil and gas industry related to the 2012 Oil and Gas NESHAP (National Emission Standard for Hazardous Air Pollutants) final rule.
6. **Proposed Permit Streamlining Amendments to Indian Country FIP:** April 2018 proposed amendments to the 2016 Indian Country FIP for Uintah and Ourary Indian Reservations that limits emissions of harmful air pollutants while preserving important, streamlined permitting processes.

EPA Proposes Amendments to the 2016 New Source Performance Standards for the Oil and Natural Gas Industry: Fact Sheet

Overview of Action

- On September 11, 2018, the U.S. Environmental Protection Agency (EPA) proposed target improvements to the 2016 New Source Performance Standards (NSPS) for the Oil and Natural Gas Industry, including amendments to the fugitive emissions monitoring requirements in the rule. The proposal would significantly reduce regulatory burden, saving the industry tens of millions of dollars in compliance costs each year. The changes also would streamline requirements and improve alignment between EPA's rule and existing state programs.
- The proposed amendments address a range of technical issues in response to administrative petitions and would clarify certain requirements in the rule. They include proposed changes to the frequency for monitoring fugitive emissions (also known as "leaks") at well sites and compressor stations; requirements for pneumatic pumps at well sites, and requirements that a professional engineer certify when meeting those requirements is technically infeasible. The Agency also is proposing amendments to requirements that a professional engineer certify the design of closed vent systems; and requirements for requesting alternative means of emissions limitations.
- The proposal changes address implementation issues that have been brought to the Agency's attention in the two years since the final standards were issued, including clarifying the acceptable location of separators used during well completions, clarifying the definition of "well site" to avoid unintended burdens on third parties, and correcting the definition of "capital expenditure" for onshore natural gas processing plant requirements. In addition, this action would make technical corrections and amendments to further clarify the rule.
- EPA's regulatory impact analysis (RIA) estimates that the proposed amendments would save the oil and gas industry up to $75 million a year, or a total of $484 million for the 2019-2025 period (3 percent discount rate). The RIA also shows that the savings are estimated at $73 million a year, for a total of $424 million from 2019 through 2025 (7 percent discount rate).
- The Agency continues to consider broad policy issues in the 2016 rule, including the regulation of greenhouse gases in the oil and natural gas sector. These issues will be addressed in a separate proposal at a later date.
- EPA will take comment the proposed rule for 60 days after the proposal is published in the Federal Register and will hold a public hearing in Denver. Details about the public hearing will be available shortly.

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Summary of Proposed Targeted Improvements

Changes to fugitive emissions (leaks) requirements

- "Fugitive emissions," can occur at several points at a well site or compressor station when connections are not properly fitted, hatches are not properly weighted and sealed, or when seals and gaskets start to deteriorate.
- The 2016 NSPS required that owners/operators develop and implement a fugitive emissions monitoring plan at oil and natural gas well sites and at compressor stations. The rule set a schedule for monitoring and for repairing any leaking components found.
- The proposed amendments would modify the schedule for fugitive emissions monitoring at both well sites and compressor stations, along with the schedule for making repairs. Owners/operators would be allowed to apply to conduct the surveys using emerging technologies, and the proposal clarifies requirements for doing so. In addition, the amendments would establish alternative fugitive emissions standards that are based on requirements established by certain states.

Proposed monitoring frequency for well sites

- The 2016 NSPS required owners/operators at new and modified well sites to conduct an initial monitoring survey within 60 days of the startup of production, and semiannual monitoring surveys afterward. After the 2016 rule was issued, EPA received petitions seeking changes to several aspects of the monitoring frequency, along with requests for exemptions to monitoring requirements for low production well sites and well sites located on the Alaskan North Slope.
- EPA is proposing the following requirements for monitoring fugitive emissions at new and modified well sites:
    - For low production well sites, biennial monitoring would be required (once every other year). A low production well site has a combined oil and natural gas production of less than 15 barrels of oil equivalent per day, averaged over the first 30 days of production.
    - For well sites that are not low production, annual monitoring would be required. Non-low production well sites are those with a combined oil and natural gas production of 15 or more barrels of oil equivalent per day, averaged over the first 30 days of production.
    - For all well sites, EPA is proposing to allow monitoring to be stopped once all major production and processing equipment is removed so that the site contains only wellheads. However, separate tank batteries receiving oil or gas produced from wellhead-only sites are considered modified and would be subject to fugitive emissions monitoring requirements.

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- EPA addressed requirements for well sites on the Alaskan North Slope in final amendments that the Agency issued in March 2018 to address significant and immediate compliance concerns. The March amendments required well sites on the Alaskan North Slope to be monitored annually (at least nine months apart); today's proposal would further change the monitoring schedule to require that *low-production* well sites be monitored every other year.

- EPA is seeking comment on a number of aspects of the fugitive emissions requirements, including the proposed schedule for initial monitoring, the frequency of monitoring, repair requirements, proposed changes to definitions in the rule, and supporting information.

Proposed monitoring frequency for compressors stations

- The 2016 rule also required monitoring for fugitive emissions at new and modified gathering and boosting compressor stations, and at transmission and storage compressor stations. The rule required an initial monitoring survey within 60 days after startup of a new or modified compressor station, then quarterly monitoring afterward. EPA is co-proposing changing the monitoring schedule to require either semi-annual or annual monitoring.

- Because some of the individual compressors at a station may not be operating when a monitoring survey is conducted, the proposal would require owners or operators to keep a record of the operating mode of each compressor at the station at the time of the survey. Owners/operators also would be required to monitor each compressor at the station at least once per calendar year when it is operating.

Compressor Stations on the Alaskan North Slope

- EPA is proposing separate monitoring requirements for compressor stations located on the Alaskan North Slope to accommodate the area's arctic climate. The Alaskan North Slope extends from the Brooks mountain range to the Arctic Ocean.

- The proposed changes for compressor stations on the Alaskan North Slope mirror those the Agency issued in March 2018 for well sites:

    - New or modified compressor stations that begin operation between September and March would be required to conduct initial leaks monitoring surveys within six months after startup or by June 30, whichever is later. Subsequent monitoring would be required annually.

    - New or modified compressor stations that begin operation between April and August would be required to conduct initial monitoring surveys within 60 days of the startup of production. Subsequent monitoring would be required annually.

    - EPA is proposing the amendments after considering concerns about implementation challenges raised in comments on Notices of Data Availability the Agency issued in 2017. Those comments noted that the monitoring technologies specified in the 2016

rule cannot reliably detect methane emissions for much of the year because of extremely cold temperatures. Temperatures in the North Slope region often are below zero.

Initial monitoring for fugitive emissions

- EPA also is seeking comment on whether to extend the 60-day time for conducting initial monitoring surveys for all well sites and compressor stations -- including those located on the Alaskan North Slope -- to allow additional time to install equipment.

Schedule for repairing leaks

- The 2016 NSPS requires owners/operators who find fugitive emissions to repair leaking components within 30 days after the emissions are detected. Owners/operators must then re-survey the component within 30 days to verify that the repair was successful.

- Because these requirements may create unintended compliance issues in instances where the repair is unsuccessful, EPA is proposing to amend the repair requirements so that owners/operators would have up to 60 days after fugitive emissions are detected to *complete* repairs; they would have to make a first attempt at repair during the first 30 days of that period. The proposal includes definitions for "first attempt at repair" and "repaired."

Improved Alignment with State Programs

- The proposed amendments would allow owners/operators to meet certain existing state requirements as alternatives to meeting specific aspects of EPA's fugitives requirements for well sites and/or compressor stations. These include requirements such as monitoring, repair and recordkeeping. Not all states have separate requirements for addressing fugitive emissions; some do so by incorporating EPA's requirements in their rules.

- In the 2016 rule, EPA noted that it had been unable to conclude that any state or local program for addressing fugitive emissions could be deemed to be "at least equivalent" to the requirements in the NSPS due to differences in both the sources covered and in specific requirements. The 2016 rule allowed owners/operators to use the alternative means of emissions limitation (AMEL) process to request permission to meet a state or local program in lieu of EPA's requirements; however, both petitioners and states questioned the practicality of doing so.

- After additional review of state and local programs for addressing fugitive emissions, EPA has determined that several are at least equivalent to the fugitive emissions monitoring, repair and recordkeeping requirements included in the proposed rule. Based on this evaluation, EPA is proposing to allow owners/operators to choose to base fugitive emissions monitoring and repair plans on requirements from certain states, in lieu of the requirements in the NSPS. Those states are:

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1. California (well sites and compressor stations)
2. Colorado (well sites and compressor stations)
3. Ohio (well sites and compressor stations)
4. Pennsylvania (well sites and compressor stations)
5. Texas (well sites)
6. Utah (well sites)

- Owners/operators would be required to notify EPA at least 90 days in advance that they intend to use a particular state's fugitive emissions standards as an alternative standard.

Standards for pneumatic pumps at well sites

- EPA is proposing to amend several aspects of the requirements for pneumatic pumps, including:
    - a requirement that a professional engineer certify when it is technically infeasible to route emissions from a pneumatic pump to a control device or process, and
    - the definition of "greenfield site" as it relates to those requirements.
- Pneumatic pumps use gas pressure to drive fluids. These pumps are used at oil or natural gas production sites where electricity is not readily available. At well sites, pneumatic diaphragm pumps are used to transfer fluids or to circulate glycol "heat trace medium," which is used to keep pipes and equipment from freezing, for example.
- Based on concerns raised in administrative petitions for reconsideration of the rule, EPA is proposing to expand a technical infeasibility provision to include all well sites – both those considered to be "greenfield" (new) sites and those that are not.
    - The 2016 rule required the routing of methane and volatile organic compound (VOC) emissions from diaphragm pumps at natural gas well sites to an existing control device or process on site (such as a device to control emissions from other equipment) unless it is technically infeasible to do so. This exemption was allowed only for "non-greenfield" (existing) well sites, based on an assumption that the technical infeasibility in routing emissions at an existing well site could be addressed in advance when new well sites are developed.
    - The Agency is seeking comments and examples of circumstances at new well sites that would make it technically infeasible to control pneumatic pump emissions, along with information about additional costs that an owner/operator may incur as a result of installing controls that also would accommodate pneumatic pump emissions at a new well site.

Professional engineer certifications

- The 2016 rule required that a qualified professional engineer certify when it is technically infeasible to route pneumatic pump emissions to an existing control or process. In response

to issues raised in petitions for reconsideration, EPA is proposing to amend the certification requirements to allow either a professional engineer or in-house engineer with appropriate expertise to make those certifications.

- Similarly, EPA is proposing to allow in-house engineers with appropriate expertise to evaluate designs of closed vent systems and certify that their design and capacity are sufficient to route emissions to a control device from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels.

Alternative means of emissions limitations

- An alternative means of emissions limitation, or AMEL, refers to the use of different types of work practices to accomplish emissions reductions that are equal to or greater than a work practice specified in the rule. The 2016 NSPS included provisions to allow owners and operators to request an AMEL for monitoring for, and reducing, fugitive emissions from well sites and compressor stations, and a separate AMEL for limiting emissions from well completions and reciprocating compressors.

- After the 2016 rule was issued, several stakeholders identified a need to streamline the process for requesting AMELs. To address this need, EPA is proposing to clarify that an individual AMEL application may include the same technology for multiple sites, provided the required information is provided for each site – including a demonstration of emission reduction equivalency for each site included in the application.

- The proposed amendments also would allow owners/operators to join with manufacturers, vendors or trade associations to apply for an AMEL that incorporates the use of emerging technologies. Applications would be required to include site-specific procedures for ensuring that emission reductions would be continuous.

- EPA also is proposing to allow applicants to supplement field data with test data, modeling analyses and other documentation, provided the field data provides information related to seasonal variations.

Cost Savings and Emissions Reductions

- EPA has analyzed the costs savings that would occur if the technical amendments are finalized as proposed, along with emission reductions that would not occur.

- The regulatory impact analysis (RIA) for the proposal estimates that the oil and gas industry would save a total of $380 million (present value using a 7 percent discount rate) and $484 million (3 percent discount rate) from 2019 through 2025, or $66 million and $75 million a year (7 percent and 3 percent discount rates, respectively), assuming *semiannual* monitoring is required at compressor stations. The total cost savings include both the cost savings associated with proposed changes to requirements in the rule and the forgone value of natural gas that would not be recovered as a result of those changes.

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- EPA's analysis estimates the following emissions reductions would not occur from 2019 through 2025 as a result of the proposed amendments if *semiannual* monitoring is required at compressor stations: 380,000 short tons of methane (8.5 million metric tons of carbon dioxide equivalent); 100,000 tons of VOCs; and 3,800 tons of hazardous air pollutants. The analysis also estimates the total present value of climate benefits that would not occur at $13.5 million (7 percent discount rate) and $54 million (3 percent discount rate), or $2.3 and $8.3 million a year, using 7 percent and 3 percent discount rates, respectively.
- EPA's analysis estimates the total net present value, assuming semiannual monitoring at compressor stations is required, is $367 million (7 percent discount rate) and $431 million (3 percent discount rate), or $64 million and $67 million a year (7 percent and 3 percent discount rates, respectively).
- The RIA also estimates the total cost savings and the emission reductions that would not occur if *annual* monitoring is required at compressor stations. Under this option, the oil and gas industry would save a total of $424 million from 2019 through 2025 (present value using a 7 percent discount rate), or $73 million a year.
- The analysis estimates the following emissions reductions would not occur from 2019 through 2025 if *annual* monitoring of compressor stations is required: 480,000 short tons of methane (11 million metric tons of carbon dioxide equivalent); 120,000 tons of volatile organic compounds; and 4,700 tons of hazardous air pollutants.

How to Comment

- EPA will take public comment on the proposed amendments for 60 days after they are published in the Federal Register. There are multiple ways to submit written comments. Please use one of the methods below to ensure EPA receives your comments.
- **The Docket ID number for the proposed amendments is EPA-HQ-OAR-2017-0483.**
- Label your comments with the Docket ID number, then submit them by any one of the following methods:
    - Online - go to www.regulations.gov and type the Docket ID number above in the search box. Click on the "Comment Now!" button at the top right of the page, and follow the instructions for submitting your comments.
    - E-mail: Send comments by e-mail to a-and-r- Docket@epa.gov, Attention Docket ID EPA-HQ-OAR-2017-0483. Please include the docket number in the subject line of your email message.
    - Fax: You may fax your comments to: (202) 566-9744, Attention Docket ID. No. EPA-HQ-OAR-2017-0483

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- NOTE: Confidential Business Information (CBI), or other information that is subject to disclosure restrictions by law, should never be sent to EPA electronically. If you have questions about submitting CBI or other information subject to disclosure restrictions by law, please visit http://www2.epa.gov/dockets/commenting-epa-dockets for additional information.

- Mail: You may mail your comments to Environmental Protection Agency, EPA Docket Center (EPA/DC), Mail Code 28221T, Attention Docket ID No. EPA-HQ-OAR-2017-0483, 1200 Pennsylvania Avenue, NW, Washington, DC 20460.

- Hand delivery/courier delivery: Comments may be delivered to EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Ave., NW, Washington, D.C. 20004, Attention Docket ID No. EPA-HQ-OAR-2017-0483. Please note that hand/courier deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

- For tips on submitting comments, see https://www.epa.gov/dockets/commenting-epadockets

For additional information

- To read the proposed amendments, visit https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/actions-and-notices-about-oil-and-natural-gas#regactions

ED_002880A_00070667-00008

Message

From: Joanne O'Loughlin [joloughlin@scainc.com]
Sent: 2/20/2019 4:36:00 PM
To: Hambrick, Amy [Hambrick.Amy@epa.gov]; Marsh, Karen [Marsh.Karen@epa.gov]
CC: Phil Norwood [pnorwood@scainc.com]
Subject: Draft Comment Excerpts - Sections XIV. Other Comments (Proposed Targeted Reconsideration Amendments to the NSPS at 40 CFR Part 60, Subpart OOOOa)
Attachments: XIV_Other Comments_TargRecon_02202019.docx

Amy/Karen,

Attached are the subject draft comment excerpts (with an overview of comments provided) for Ex. 5 Deliberative Process (DP) Comments).

We will send the updated excerpt transmittal tracking sheet reflecting this submission and a submission that will be provided later today for Ex. 5 Deliberative Process (DP) when the latter submission is sent.

The excerpts for section are currently organized under the following headings:

Ex. 5 Deliberative Process (DP) **Comments**

Ex. 5 Deliberative Process (DP)

The miscellaneous "other comments" included under section cover several topics. Some comments are related placeholders, e.g., for cited references Ex. 5 Deliberative Process (DP) commenters that endorsed or incorporated the comments of another commenter Ex. 5 Deliberative Process (DP) and do not require a response from the EPA.

An overview of the miscellaneous "Other Comments" that cover topics that the EPA may want to consider and potentially respond to is provided below. Some of these comments, though related, may be determined to be "Out of Scope" and can be easily moved to that section.

-
-
-
-
-
-
-
-
-

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Regards,

Joanne O'Loughlin

Ex. 6 Personal Privacy (PP)

www.scainc.com

This email may contain privileged and confidential information intended only for the use of the specific entity named herein.

Message

From: Joanne O'Loughlin [joloughlin@scainc.com]
Sent: 2/19/2019 3:52:28 PM
To: Hambrick, Amy [Hambrick.Amy@epa.gov]
CC: Phil Norwood [pnorwood@scainc.com]; Tanya Parise [tparise@scainc.com]
Subject: Draft Comment Excerpts - Sections V, XI.A., XI.G., and XIII (Proposed Targeted Reconsideration Amendments to the NSPS at 40 CFR Part 60, Subpart OOOOa)
Attachments: V_Impact of Fugitive Emissions Requirements on Small Businesses_TargRecon_02192019.docx; XI.A_Reciprocating Compressors_TargRecon_02192019.docx; XI.G_Implementation Transition Guidance_Clarifications_TargRecon_02192019.docx; XIII_Statutory and Executive Order Reviews_TargRecon_02192019.docx; Draft Excerpt Tracking Sheet - TargRecon Excerpts_02192019.xlsx

Amy/Karen,

Attached are the subject draft comment excerpts (with an overview of comments provided) for sections

Ex. 5 Deliberative Process (DP)

I have also attached an updated excerpt transmittal tracking sheet reflecting these submissions.

The excerpts for section Ex. 5 Deliberative Process (DP) are currently organized under the following sections:

Ex. 5 Deliberative Process (DP)

Industry comments:

- Ex. 5 Deliberative Process (DP)

Joint Environmental Commenters:

- Ex. 5 Deliberative Process (DP)

The singular excerpt for section Ex. 5 Deliberative Process (DP) is currently under the following section:

Ex. 5 Deliberative Process (DP)

The excerpts for section Ex. 5 Deliberative Process (DP) are currently included under the following section:

Ex. 5 Deliberative Process (DP)

The excerpts for section Ex. 5 Deliberative Process (DP) are currently included under the following sections:

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Regards,

Joanne O'Loughlin

Ex. 6 Personal Privacy (PP)

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This email may contain privileged and confidential information intended only for the use of the specific entity named herein.

Message

From: Hambrick, Amy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=787B0A3376944FCABAED4F018432CF44-AHAMBRIC]
Sent: 9/12/2017 9:31:33 PM
To: Hambrick, Amy [Hambrick.Amy@epa.gov]
Subject: FW: OilGas
Attachments: Reconsideration Pager_2017-01-11 (002).docx

Outstanding Items: Oil Gas NSPS Reconsideration

Ex. 5 Deliberative Process (DP)

ADP Phase: Early Guidance

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

- Ex. 5 Deliberative Process (DP)

- Ex. 5 Deliberative Process (DP)

State Outreach

- Ex. 5 Deliberative Process (DP)

Hey team –

Yesterday afternoon I had a briefing with Peter on the Control Technology Review with Angie and Ravi. Penny, David, and Kevin C. were in attendance. Peter spent the entire hour discussing his ideas on the OOOOa reconsideration.

Essentially, the CTR team has been briefing Peter on the equipment, operations, and emissions in each segment of the

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

He also mentioned the possibility of Ex. 5 Deliberative Process (DP) Obviously we'll need to find out more about this.

He mentioned again the Ex. 5 Deliberative Process (DP)

The next steps are to schedule a joint meeting with the CTR team (me, angie, ravi, and nick h.) and the rule team. Peter also wants us to start engaging with OAP again, mentioning Suzie in particular. Amy – I think it's more appropriate for the rule lead to schedule this, and not me – are you okay with setting this up? After that, Peter would like a debrief on what we've come up with. Peter stressed the urgency of this, a Ex. 5 Deliberative Process (DP)
Ex. 5 Deliberative Process (DP)

Just so you all know, I mentioned several times during this discussion that the right people weren't in the room for this brainstorming session – and David also was uncomfortable with Peter having this braindump without you guys there. I know there's a lot of moving parts in this reconsideration, and we're all doing our best to communicate. Let me know if you have any ideas on how to handle situations like this in the future – sharing my notes is obviously the bare minimum, and I can commit to bringing my laptop in the future so I can alert you all to come upstairs if you're available. I'm sure Peter is bringing up new ideas in meetings on your other projects (AWP, NESHAP, CTG, etc) as well – hopefully we can all have a plan so the whole team can get this information in a timely fashion.

Thanks,
Lisa

Amy Hambrick
U.S. Environmental Protection Agency
(919)541-0964

From: Hambrick, Amy
Sent: Tuesday, August 15, 2017 4:40 PM
To: Hambrick, Amy <Hambrick.Amy@epa.gov>
Subject: FW: OilGas

Source specific conversations from peter Ex. 5 Deliberative Process (DP)
Ex. 5 Deliberative Process (DP)
-early guidance first , then set up individual source conversation with peter

-still follow what came from the retreat

From: Hambrick, Amy
Sent: Tuesday, August 08, 2017 1:42 PM
To: Hambrick, Amy <Hambrick.Amy@epa.gov>
Subject: OilGas

Next Steps To Expect:

- Outreach followup 8/8 with Peter
- EG draft sent to group for feedback by 8/4
- Schedule next OGC followup post Peter
- Set up issue specific brainstorming
- Schedule EG check in with Peter// PPT or Pager format?
- Verify new docket is established
- Put draft preamble rule together

From: Hambrick, Amy
Sent: Tuesday, July 18, 2017 4:57 PM
To: Thompson, Lisa <Thompson.Lisa@epa.gov>; Witosky, Matthew <Witosky.Matthew@epa.gov>; Marsh, Karen <Marsh.Karen@epa.gov>; Witt, Jon <Witt.Jon@epa.gov>; Miller, Elizabeth <Miller.Elizabeth@epa.gov>; Garwood, Gerri <Garwood.Gerri@epa.gov>
Cc: Cozzie, David <Cozzie.David@epa.gov>
Subject: Oil Gas Reconsideration Early Guidance Draft

Hi All,

I've started drafting what we could use as a starting point for the Early Guidance briefing process (starting with Peter and per Peter not calling it EG) for the OG reconsideration. After reviewing our previous EG briefings and recognizing that the new DC team seems to want to focus on issues and solutions, I've tried to focus on "the standard", "the issue", and "path to resolution". I've limited the background information but have not eliminated it completely. I think at this point it may be best to stick with concepts until we get additional feedback from management, but I'd really appreciate your input—if you think there is a better way to present this, please share! I think there may be other items we want to try to raise or work in, again, I'm happy to hear your suggestions.

Please add your edits by COB July 27 (I just made this up, so if you need more time, just let me know).

Ex. 5 Deliberative Process (DP)

FYI: This is what was shared with Peter as potential schedules. Who knows how this will really play out.

Option 1 – Robust scope

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Option 2 – Limited scope

Ex. 5 Deliberative Process (DP)

From: Hambrick, Amy
Sent: Wednesday, June 14, 2017 4:08 PM
To: Cozzie, David <Cozzie.David@epa.gov>; Thompson, Lisa <Thompson.Lisa@epa.gov>; Witosky, Matthew <Witosky.Matthew@epa.gov>; Marsh, Karen <Marsh.Karen@epa.gov>; Witt, Jon <Witt.Jon@epa.gov>; Carey, Angela <Carey.Angela@epa.gov>
Subject: OilGas Reconsideration Follow Up

All-

Thanks for discussing the OG reconsideration yesterday. As we discussed the below action items came out of the June 1 meeting with Peter:

- Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Please add your comments on the below drafts by COB 6/19 (if this isn't reasonable, just let me know). If there is anything I missed or may have mischaracterized, please don't hesitate to add to this email or correct me.

1-pager:

Ex. 5 Deliberative Process (DP)

Tier 1 Justification:

Ex. 5 Deliberative Process (DP)

Tracker Abstract (Internal and External)

Ex. 5 Deliberative Process (DP)

Thank you,

Amy

From: Hambrick, Amy
Sent: Monday, August 07, 2017 3:00 PM
To: Hambrick, Amy <Hambrick.Amy@epa.gov>
Subject: OilGas

Ex. 5 Deliberative Process (DP)

End of day 2-3 x week
Tuesday 930-1015
Checkin prior too Tuesday meeting (Monday night or Tuesday morning) and maybe right after staff meeting on Thursday morningse

Ex. 5 Deliberative Process (DP)

List cross agency of workgroups and federal agencies of OG stuff going on

Ex. 5 Deliberative Process (DP)

Still want me to lead the meeting- yes
Expand agenda with team report out, etc. somehow update
Reemphasize team charter etc… and finalize list of who is doing what .. what purpose does each serve –is there a need for each team … where is the need; how overlap with W really work what it readlly means… etc
Jennifer Snyder

Brown bag re: studies

Ex. 5 Deliberative Process (DP)

What are we missing from the Regional calls ?—need to build a report with all the regional contacts – need individial phone calls

Maintain a couple HFPOC contact- not sure what will happen with this

Interaction with industry----

Need to get a sense of how ppl work respect that and yet get the work done--- im their peer

I need to elevate things to David more

For report outs how to get people to provide enough—there needs to be enough shared back—need to ask probing questions

Need bigger room E101??? 201??

How to encompass a team back into a bigger team

Need to add hillary ward topic to Tuesday regarding amel delegation

OG website- refresh

Ex. 5 Deliberative Process (DP)

(3) HFPOC

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

I need to get full list of HPFOC contacts

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Get the SharePoint mobile app!

Here is the strawman we discussed today. Please markup/send comments by Friday, January 13.

Ex. 5 Deliberative Process (DP)

Here's the document that Howard, Jodi shared with you.

Ex. 5 Deliberative Process (DP)

Here's the folder that Thompson, Lisa shared with you.

Go Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

You're now a member of the Oil and Gas Docket group

Ex. 5 Deliberative Process (DP)

Private group - View members

Ex. 5 Deliberative Process (DP)

Amy Branning	Ex. 5 Deliberative Process (DP)	
David Cozzie		
Mark de Figueiredo		
Stephen Edgerton		
Graham Fitzsimons		
Gerri Garwood		
Amy Hambrick		
Veronica Hanzel		
Jeff Harris		
David Hendricks		
Jodi Howard		
Alex MacPherson		
Alexis McKittrick		
Glenn Meganck		
Marcia Mia		
Bruce Moore		
Brian Nelson		
Tanya Parise		
Mike Pring		
Amanda Singleton		
Charlene Spells		
Lesley Stobert		
Lisa Thompson		
Suzie Waltzer		
Melissa Weitz		
Alden West		
Matt Witosky		

Message

From: Hoffman, Howard [hoffman.howard@epa.gov]
Sent: 11/30/2018 2:34:20 PM
To: Branning, Amy [Branning.Amy@epa.gov]; Marks, Matthew [Marks.Matthew@epa.gov]
CC: Mills, Derek [Mills.Derek@epa.gov]
Subject: Re: More talking points for the Ex. 5 Deliberative Process (DP) if we want to add them -- FW: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3
Attachments: Oil Gas Talking Points_HJH_11-30-18.docx

That's a good point, Amy, thx. I changed the sentence to read Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

From: Branning, Amy
Sent: Friday, November 30, 2018 8:15:09 AM
To: Hoffman, Howard; Marks, Matthew
Cc: Mills, Derek
Subject: RE: More talking points for the Ex. 5 Deliberative Process (DP) if we want to add them -- FW: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3

Howard:

I thought Ex. 5 Deliberative Process (DP)
Ex. 5 Deliberative Process (DP)

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

This message may contain sensitive, privileged information covered by the deliberative process, attorney-client and/or attorney work product privileges. If you believe you have received this e-mail in error, please notify me and delete the e-mail immediately.

From: Hoffman, Howard
Sent: Thursday, November 29, 2018 7:25 PM
To: Marks, Matthew <Marks.Matthew@epa.gov>
Cc: Mills, Derek <Mills.Derek@epa.gov>; Branning, Amy <Branning.Amy@epa.gov>
Subject: More talking points for the Ex. 5 Deliberative Process (DP) if we want to add them -- FW: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3

Based on the e-mail, below, from Amy Hambrick, we could add another sentence or two to the talking points for Ex. 5 Deliberative Process (DP)
Ex. 5 Deliberative Process (DP) I added them in the track changes in the attached document, Oil Gas Talking Points_HJH_11-29-18. If they look OK, suggest just sending this on to Rob.

Howard J. Hoffman USEPA-OGC-ARLO (202) 564-5582(O) (240)-401-9721(C) Room 7415 WJC-North
Mailing address: Mail Code 7344A, 1200 Pennsylvania Ave. NW Washington, D.C. 20460

The contents of this message may be subject to the attorney-client, work-product, or deliberative process privileges.

From: Hambrick, Amy
Sent: Thursday, November 29, 2018 2:25 PM
To: Hoffman, Howard <hoffman.howard@epa.gov>
Subject: RE: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3

Hi Howard- sorry for the delay in responding. This is what I am aware of as to what OAR has publicly said. I am not aware of any talking points related to Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

1. Public Reg Agenda (Fall 2018)- https://www.reginfo.gov/public/do/eAgendaViewRule?pubId=201810&RIN=2060-AT90 (Note it was also in the Spring 2018 reg agenda)

EPA/OAR **RIN:** 2060-AT90 **Publication ID:** Fall 2018

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

Abstract:
On June 3, 2016, the Environmental Protection Agency (EPA) published a final rule titled "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule." Following promulgation of the final rule, the Administrator received petitions for reconsideration of several provisions of the rule. The EPA is addressing those specific reconsideration issues in a separate proposal. A number of states and industry associations sought judicial review of the rule, and the litigation is currently being held in abeyance. On March 28, 2017, newly elected President Donald Trump issued Executive Order 13783 titled "Promoting Energy Independence and Economic Growth," which directs agencies to review existing regulations that potentially burden the development of domestic energy resources, and appropriately suspend, revise or rescind regulations that unduly burden the development of U.S. energy resources beyond what is necessary to protect the public interest or otherwise comply with the law. In 2017, the EPA provided notice to initiate the review of the 2016 rule and stated that, if appropriate, it will initiate proceedings to suspend, revise or rescind the rule. Subsequently, in a notice dated June 5, 2017, the EPA further committed to look broadly at the entire 2016 rule. The purpose of this action is to propose amendments to address key policy issues, such as the regulation of greenhouse gases, in this sector.

Agency: Environmental Protection Agency(EPA)

Priority: Other Significant

RIN Status: Previously published in the Unified Agenda

Agenda Stage of Rulemaking: Proposed Rule Stage

Major: No

Unfunded Mandates: No

EO 13771 Designation: Deregulatory

CFR Citation: 40 CFR 60

Legal Authority: 42 U.S.C. 7401 et seq., Clean Air Act

Legal Deadline: None

Statement of Need:
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." On March 28, 2017, newly elected President Donald Trump issued Executive Order 13783 titled "Promoting Energy Independence and Economic Growth," which directs agencies to review existing regulations that potentially burden the development of domestic energy resources, and appropriately suspend, revise or rescind regulations that unduly burden the development of U.S. energy resources beyond what is necessary to protect the public interest or otherwise comply with the law. In 2017, the EPA provided notice to initiate the review of the 2016 rule and stated that, if appropriate, it will initiate proceedings to suspend, revise or rescind the rule. Subsequently, in a notice dated June 5, 2017, the EPA further committed to look broadly at the entire 2016 rule. The purpose of this action is to propose amendments to address key policy issues, such as the regulation of greenhouse gases, in this sector. This proposal will solicit comments and/or information from the public regarding the Agency's proposed requirements and options under consideration. These amendments are anticipated to remove regulatory duplication in an effort to reduce burden.

Summary of the Legal Basis:

The review of the 2016 OOOOa rule is an exercise of the EPA's authority under section 111(b)(1)(B), section 307(d)(7)(B) and section 301(a) of the Clean Air Act.

Alternatives:
For the 2016 OOOOa review proposal, we anticipate soliciting comment on a lead policy option for the regulation of greenhouse gases and the sector regulatory structure and an alternative policy option under consideration.

Anticipated Costs and Benefits:
These values are estimates that are likely to change. Note all values at 7 percent discount rate in 2016 dollars. Total Present Value of Cost (2019 through 2025): $101 million Costs Annually: $18 million Forgone Benefits (2019 through 2025); $13 million Forgone Benefits Annually: $2.3 million

Risks:
We do not anticipate any risks to health related to this action.

Timetable:

Action	Date	FR Cite
NPRM	12/00/2018	
Final Rule	06/00/2019	

Additional Information: Docket #:EPA-HQ-OAR-2017-0757

Regulatory Flexibility Analysis Required: No

Government Levels Affected: None

Small Entities Affected: No

Federalism: No

Included in the Regulatory Plan: Yes

RIN Information URL: https://www.epa.gov/stationary-sources-air-pollution/clean-air-act-standards-and-guidelines-oil-and-natural-gas-industry

Sectors Affected: 211111 Crude Petroleum and Natural Gas Extraction; 211112 Natural Gas Liquid Extraction; 221210 Natural Gas Distribution; 486110 Pipeline Transportation of Crude Oil; 486210 Pipeline Transportation of Natural Gas

RIN Data Printed in the FR: No

Agency Contact:
Amy Hambrick
Environmental Protection Agency
Office of Air and Radiation
109 T.W. Alexander Drive, Mail Code E143-05,
Research Triangle Park, NC 27711
Phone:919 541-0964
Fax:919 541-0516
Email: hambrick.amy@epa.gov

2. As Derek referenced below, Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Amy

Amy Hambrick
U.S. Environmental Protection Agency
(919)541-0964

From: Hoffman, Howard
Sent: Wednesday, November 28, 2018 1:07 PM
To: Hambrick, Amy <Hambrick.Amy@epa.gov>
Subject: Fw: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3

Amy -- we are looking for any information about the Ex. 5 Deliberative Process (DP) that is already publicly available, which we'd like to use for an upcoming speech by the General Counsel, Matt Leopold. Pls see Derek Mills's e-mail immediately below Ex. 5 Deliberative Process (DP) Ex. 5 Deliberative Process (DP) Thx much.

From: Mills, Derek
Sent: Wednesday, November 28, 2018 12:12 PM
To: Marks, Matthew; Branning, Amy; Hoffman, Howard
Subject: RE: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3

Howard,

On second thought, Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Derek Mills
Attorney, Office of General Counsel
U.S. Environmental Protection Agency
(202) 564-3341

From: Mills, Derek
Sent: Wednesday, November 28, 2018 11:47 AM
To: Marks, Matthew <Marks.Matthew@epa.gov>; Branning, Amy <Branning.Amy@epa.gov>; Hoffman, Howard <hoffman.howard@epa.gov>
Subject: RE: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3

Yes. I can work on this. **Howard**, do you want to draft a few short bullets for Ex. 5 Deliberative Process (DP) and send them to me? I can then send around a full draft to this group. Thanks!

Derek Mills
Attorney, Office of General Counsel
U.S. Environmental Protection Agency
(202) 564-3341

From: Marks, Matthew
Sent: Wednesday, November 28, 2018 10:44 AM
To: Branning, Amy <Branning.Amy@epa.gov>; Mills, Derek <Mills.Derek@epa.gov>; Hoffman, Howard <hoffman.howard@epa.gov>
Subject: FW: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3

FYI – Looks like we need to develop some O&G talking points for Matt by cob Monday. I'll let you know if we get more direction from Rob, but I think we should Ex. 5 Deliberative Process (DP) Ex. 5 Deliberative Process (DP) Derek, given your time in the Front Office, I assume you are familiar with the level of detail Matt likes?

From: Zenick, Elliott
Sent: Wednesday, November 28, 2018 10:28 AM
To: Stachowiak, Robert <Stachowiak.Robert@epa.gov>; Srinivasan, Gautam <Srinivasan.Gautam@epa.gov>
Cc: Marks, Matthew <Marks.Matthew@epa.gov>
Subject: RE: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3

Looping in Matt Marks since he will coordinate on (1). Please note that there are Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Here is the link to publicly available information:

https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/actions-and-notices-about-oil-and-natural-gas#regactions

Acting Deputy Associate General Counsel – ARLO
(202)564-1822

From: Stachowiak, Robert
Sent: Wednesday, November 28, 2018 10:14 AM
To: Srinivasan, Gautam <Srinivasan.Gautam@epa.gov>; Zenick, Elliott <Zenick.Elliott@epa.gov>
Subject: Request for assistance with talking points for December 7 speaking event at ELI by COB Monday December 3

Hi Gautam and Elliott -

Matt is giving a keynote address at an event hosted by the Rocky Mountain Mineral Law Foundation on Friday December 7. The audience is legal/non-legal professionals in the oil/gas and natural resources area, including industry, government, academics, and NGOs. Here is the session description:

8:10 am – 8:40 am

Keynote Presentation—Environmental Priorities for the Trump Administration

- Trump Administration's environmental priorities for oil, gas, and the natural resource industries
- Where the Administration is currently focused, why it has made certain changes, and its plans going forward

Matt would like to address **Ex. 5 Deliberative Process (DP)** **Ex. 5 Deliberative Process (DP)** I'm preparing talking points for him, but I could really use your help, if at all possible no later than by COB Monday December 3.

Unfortunately, I don't seem to have inherited (or at least can't locate) existing talking points or background materials (e.g., press releases) on (1) or (2) in my files. So can you please suggest talking points for those issues, such as Ex. 5 Deliberative Process (DP) **Ex. 5 Deliberative Process (DP)** (And also for (3), if it is a new issue.) He has 30 minutes to speak, and one other topic Ex. 5 Deliberative Process (DP) right now, so I expect a similar level of detail to the AAPCA talking points would be appropriate. **Ex. 5 Deliberative Process (DP)**

If you forward me on to other relevant folks in your office, please cc me and be explicit about from whom I should expect to receive the requested materials.

Thanks again for your help!

-Rob S.

Robert Stachowiak
U.S. Environmental Protection Agency
Acting Associate Deputy General Counsel
Office of General Counsel (2310A)
1200 Pennsylvania Ave., N.W.
Washington, D.C. 20460
(202) 564-0580

EPA Proposes Policy Amendments to the 2012 and 2016 New Source Performance Standards for the Oil and Natural Gas Industry

Overview of Action

- On August 28, 2019, the U.S. Environmental Protection Agency (EPA) proposed amendments to the 2012 and 2016 New Source Performance Standards (NSPS) for the Oil and Natural Gas Industry that would remove regulatory duplication and save the industry millions of dollars in compliance costs each year, while maintaining health and environmental protection from oil and gas sources that the Agency considers appropriate to regulate.
- EPA is issuing today's proposal in response to President Trump's Executive Order on Promoting Energy Independence and Economic Growth. That order directs agencies to review existing regulations that potentially "burden the development or use of domestically produced energy resources," including oil and natural gas, and to rescind or suspend regulatory requirements if appropriate.
- The proposed amendments would remove all sources in the transmission and storage segment of the oil and natural gas industry from regulation under the NSPS, both for ozone-forming volatile organic compounds (VOCs), and for greenhouse gases (GHGs). The existing NSPS regulates GHGs through limitations on emissions of methane.
- The amendments also would rescind the methane requirements in the 2016 NSPS that apply to sources in the production and processing segments of the industry.
- As an alternative, EPA also is proposing to rescind the methane requirements that apply to all sources in the oil and natural gas industry, without removing any sources from the current source category.
- As part of today's action, the Agency also is seeking comment on alternative interpretations of EPA's legal authority to regulate pollutants under section 111(b) of the Clean Air Act.
- EPA's regulatory impact analysis estimates that the proposed amendments would save the oil and natural gas industry $17-$19 million a year, for a total of $97-$123 million from 2019 through 2025.
- EPA will accept comments on all aspects of the proposed amendments for 60 days after they are published in the Federal Register. The agency will hold a public hearing on the proposed amendments in Texas. Details about the public hearing will be available shortly.
- Today's proposal is separate from EPA's September 2018 proposal to make targeted improvements to the 2016 NSPS, including amendments to the fugitive emissions (leaks) monitoring requirements in the rule. EPA expects to take final action on that proposal later this year.

Summary of Proposed Amendments

Primary Proposal

- Section 111 of the Clean Air Act requires EPA to set NSPS for categories of industrial facilities that EPA has listed because they cause, or significantly contribute to, air pollution that may endanger public health or welfare. These are called "source categories."
- The Agency's original source category listing for the oil and natural gas industry, issued in 1979, included only the production and processing segments of the industry. However, in the 2012 and 2016 NSPS rules, EPA interpreted the source category to include the industry's transmission and storage segment. In the 2016 NSPS rule, EPA also, as an alternative, expanded the source category to include the transmission and storage segment.
- EPA is proposing to remove sources in the transmission and storage segment from the oil and natural gas source category. The proposal notes that the agency erred when it interpreted or expanded the source

category in 2012 and 2016 to include the transmission and storage segment, because that segment of the industry is functionally separate from the production and processing segments. Sources in the transmission and storage segment include transmission compressor stations, pneumatic controllers, and underground storage vessels.

- In the proposal, EPA also notes that the Agency would need to make a separate finding that the transmission and storage segment contributes significantly to air pollution that is anticipated to endanger public health or welfare before those sources in that segment could be listed for regulation.
- Because the proposed amendments would remove sources in the transmission and storage segment from the source category, the proposal also would rescind the emissions limits in the 2012 and 2016 NSPS that currently apply to those sources. These include limitations on both methane emissions and emissions of VOCs.
- For the production and processing segments, the proposal would rescind emissions limits for methane but would keep emissions limits for VOCs. The proposal notes that the controls to reduce VOC emissions also reduce methane at the same time, so separate methane limitations for these segments of the industry are redundant. Sources in the production and processing segments include well completions, pneumatic pumps, pneumatic controllers, gathering and boosting compressors, natural gas processing plants, fugitive emissions, and storage tanks.
- These proposed amendments would remove the Agency's obligation to develop emission guidelines to address methane emissions from existing sources under section 111(d) of the Clean Air Act. EPA believes this would have limited environmental impact, because some existing sources that "modify" and, as a result, become subject to requirements for new sources, and because the number of remaining sources may decline over time as they are shut down or become obsolete.

Alternative Proposal

- As an alternative, EPA also is proposing to rescind the methane requirements in the NSPS for oil and natural gas sources, without removing any sources from the source category. Under this alternative, the rule would retain VOC standards for the production, processing, and transmission and storage segments of the industry. As in the primary proposal, the alternative proposal notes that because the controls to reduce VOC emissions reduce methane at the same time, separate methane limitations for the industry are redundant.

Seeking Comment on EPA's Legal Authorities to Regulate Methane

- As part of today's action, EPA also is seeking comment on alternative interpretations of the Agency's legal authority to regulate pollutants under section 111 of the Clean Air Act.
- In the 2016 rule, EPA took the position that the law did not require that the Agency, as a prerequisite to regulating methane as part of the NSPS, first make a separate, pollutant-specific determination that GHG emissions (primarily methane) from the oil and natural gas industry cause, or significantly contribute to, air pollution that may endanger public health or welfare.
- In the 2016 rule, the Agency also made a finding in the alternative if the Clean Air Act were interpreted to require a separate pollutant-specific determination. In that finding, GHG emissions (primarily methane) from the oil and gas industry do cause or contribute significantly to air pollution that may reasonably expected to endanger public health or welfare
- As part of today's proposal, EPA is seeking comment on whether the Agency should revise the positions it took in the 2016 rule. Specifically, EPA is requesting comment on:
    - Whether section 111 of the Clean Air Act requires EPA to make a pollutant-specific significant contribution finding for GHG emissions (primarily methane) from the oil and natural gas industry; and
    - If the law does require a pollutant-specific finding, whether the finding in the alternative in the 2016 rule properly satisfied that requirement.
- EPA also is seeking comment on the appropriate criteria to use when determining, under section 111,

whether a pollutant emitted from a particular source category significantly contributes to air pollution that may reasonably be anticipated to endanger public health and the environment. The Agency is seeking these comments to inform its actions in future rules.

Avoided Costs and Emissions Reductions

- EPA has analyzed costs that would be avoided and emission reductions that would not occur if the policy amendments are finalized as proposed.
- The Regulatory Impact Analysis for the proposal estimates that the oil and natural gas industry would save a total of $97 million (present value using a 7 percent discount rate) or $123 million (3 percent discount rate) from 2019 through 2025, or $17 million and $19 million a year (7 percent and 3 percent discount rates, respectively). The total cost savings reflect both the cost savings associated with proposed changes to requirements in the rule and the forgone value of natural gas that would not be recovered as a result of those changes.
- EPA's analysis estimates the following emissions reductions would not occur from 2019 through 2025 as a result of the proposed amendments: 370,000 short tons of methane (8.4 million metric tons of carbon dioxide equivalent), 10,000 short tons of volatile organic compounds, and 300 short tons of hazardous air pollutants. The analysis also estimates the total present value of climate benefits within the United States that would not occur at $13 million (under a 7 percent discount rate) or $52 million (under a 3 percent discount rate), which translates to $2.3 or $8.1 million per year, using 7 percent and 3 percent discount rates, respectively.
- These impacts are projected compared to a baseline that only includes final actions. The Regulatory Impact Analysis also presents potential impacts of this action compared to a baseline where the technical reconsideration proposed in 2018 in included.

How to Comment

- EPA will take public comment on the proposed amendments for 60 days after they are published in the Federal Register. There are multiple ways to submit written comments. Please use one of the methods below to ensure EPA receives your comments.
- **The Docket ID number for the proposed amendments is EPA-HQ-OAR-2017-0757.**
- Label your comments with the Docket ID number, then submit them by any one of the following methods:
    - Online - go to www.regulations.gov and type Docket ID number EPA-HQ-OAR-2017-0757 in the search box. Click on the "Comment Now!" button at the top right of the page and follow the instructions for submitting your comments.
    - E-mail: Send comments by e-mail to a-and-r- Docket@epa.gov, Attention Docket ID EPA-HQ-OAR-2017-0757. Please include the docket number in the subject line of your email message.
    - Fax: You may fax your comments to: (202) 566-9744, Attention Docket ID. No. EPA-HQ-OAR-2017-0757
    - NOTE: Confidential Business Information (CBI), or other information that is subject to disclosure restrictions by law, should never be sent to EPA electronically. If you have questions about submitting CBI or other information subject to disclosure restrictions by law, please visit http://www.epa.gov/dockets/commenting-epa-dockets for additional information.
- Mail: You may mail your comments to Environmental Protection Agency, EPA Docket Center (EPA/DC), Mail Code 28221T, Attention Docket ID No. EPA-HQ-OAR-2017-0757, 1200 Pennsylvania Avenue, NW, Washington, DC 20460.
- Hand delivery/courier delivery: Comments may be delivered to EPA Docket Center, Room 3334, EPA WJC West Building, 1301 Constitution Ave., NW, Washington, D.C. 20004, Attention Docket ID No. E EPA-

HQ-OAR-2017-0757. Please note that hand/courier deliveries are only accepted during the Docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

- For tips on submitting comments, see https://www.epa.gov/dockets/commenting-epadockets .

For additional information

- To read the proposed amendments, visit https://www.epa.gov/controlling-air-pollution-oil-and-natural-gas-industry/actions-and-noticesabout-oil-and-natural-gas#regactions

Message

From: Miller, Elizabeth [Miller.Elizabeth@epa.gov]
Sent: 5/22/2018 1:28:02 PM
To: Macpherson, Alex [Macpherson.Alex@epa.gov]
CC: Hoffmann, Jucilene [hoffmann.jucilene@epa.gov]
Subject: FW: EO 12866 Interagency Comments on EPA draft proposed rule titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration," (RIN 2060-AT54)

Alex,
Does Ex. 5 Deliberative Process (DP) make sense as a response to the blue highlighted comment?
I feel like Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Beth

From: Miller, Elizabeth
Sent: Monday, May 21, 2018 4:44 PM
To: Kopits, Elizabeth <Kopits.Elizabeth@epa.gov>
Cc: Marten, Alex <Marten.Alex@epa.gov>
Subject: RE: EO 12866 Interagency Comments on EPA draft proposed rule titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration," (RIN 2060-AT54)

I added an off the cuff comment on Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

From: Kopits, Elizabeth
Sent: Monday, May 21, 2018 4:39 PM
To: Miller, Elizabeth <Miller.Elizabeth@epa.gov>
Cc: Marten, Alex <Marten.Alex@epa.gov>
Subject: Re: EO 12866 Interagency Comments on EPA draft proposed rule titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration," (RIN 2060-AT54)

Thanks!

Sent from my iPhone

On May 21, 2018, at 4:27 PM, Miller, Elizabeth <Miller.Elizabeth@epa.gov> wrote:

I think I understand Ex. 5 Deliberative Process (DP)
Ex. 5 Deliberative Process (DP) I will look into this further tomorrow.

From: Kopits, Elizabeth
Sent: Monday, May 21, 2018 3:48 PM
To: Miller, Elizabeth <Miller.Elizabeth@epa.gov>
Cc: Marten, Alex <Marten.Alex@epa.gov>
Subject: FW: EO 12866 Interagency Comments on EPA draft proposed rule titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration," (RIN 2060-AT54)

FYI – I need to leave the office soon, but I don't follow the draft response to the remaining question noted in the email below.

Ex. 5 Deliberative Process (DP)

From: Marsh, Karen
Sent: Monday, May 21, 2018 1:37 PM
To: Hambrick, Amy <Hambrick.Amy@epa.gov>; Witt, Jon <Witt.Jon@epa.gov>; Witosky, Matthew <Witosky.Matthew@epa.gov>; Shappley, Ned <Shappley.Ned@epa.gov>; Garwood, Gerri <Garwood.Gerri@epa.gov>; Miller, Elizabeth <Miller.Elizabeth@epa.gov>; Hoffmann, Jucilene <hoffmann.jucilene@epa.gov>; Weitz, Melissa <Weitz.Melissa@epa.gov>; DeFigueiredo, Mark <DeFigueiredo.Mark@epa.gov>; Waltzer, Suzanne <Waltzer.Suzanne@epa.gov>; Alsalam, Jameel <Alsalam.Jameel@epa.gov>; Cozzie, David <Cozzie.David@epa.gov>; Davis, Alison <Davis.Alison@epa.gov>; Branning, Amy <Branning.Amy@epa.gov>; Chan, Elizabeth <Chan.Elizabeth@epa.gov>; Gilbreath, Jan <Gilbreath.Jan@epa.gov>; Kopits, Elizabeth <Kopits.Elizabeth@epa.gov>
Subject: RE: EO 12866 Interagency Comments on EPA draft proposed rule titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration," (RIN 2060-AT54)

All,

Thank you to everyone that has been contributing to responses to OMB's comments. It looks like we have drafted responses to most of OMB's comments. Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Karen

****

Karen R. Marsh, PE
US EPA, OAQPS, Sectors Policies and Programs Division
Fuels and Incineration Group
109 TW Alexander Drive, Mail Code E143-05
Research Triangle Park, NC 27711
Direct: (919) 541-1065; email: marsh.karen@epa.gov

From: Hambrick, Amy
Sent: Thursday, May 17, 2018 9:59 AM
To: Marsh, Karen <Marsh.Karen@epa.gov>; Witt, Jon <Witt.Jon@epa.gov>; Witosky, Matthew <Witosky.Matthew@epa.gov>; Shappley, Ned <Shappley.Ned@epa.gov>; Garwood, Gerri <Garwood.Gerri@epa.gov>; Miller, Elizabeth <Miller.Elizabeth@epa.gov>; Hoffmann, Jucilene <hoffmann.jucilene@epa.gov>; Weitz, Melissa <Weitz.Melissa@epa.gov>; DeFigueiredo, Mark <DeFigueiredo.Mark@epa.gov>; Waltzer, Suzanne <Waltzer.Suzanne@epa.gov>; Alsalam, Jameel <Alsalam.Jameel@epa.gov>; Cozzie, David <Cozzie.David@epa.gov>; Davis, Alison <Davis.Alison@epa.gov>; Branning, Amy <Branning.Amy@epa.gov>; Chan, Elizabeth <Chan.Elizabeth@epa.gov>; Gilbreath, Jan <Gilbreath.Jan@epa.gov>; Kopits, Elizabeth <Kopits.Elizabeth@epa.gov>
Subject: EO 12866 Interagency Comments on EPA draft proposed rule titled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration," (RIN 2060-AT54)

All-

OMB sent Interagency Comments. I added a place in the document for "EPA Responses" . David mentioned to me this morning that we should plan to turn these around by early next week.

Interagency Comments:

Ex. 6

Master Preamble/Rule file:

Ex. 6

Ex. 6

Amy

Message

From: Mia, Marcia [Mia.Marcia@epa.gov]
Sent: 5/24/2018 1:14:03 PM
To: Basinger, David [Basinger.David@epa.gov]; Marsh, Karen [Marsh.Karen@epa.gov]
Subject: RE: [External] RE: Method 21/LDAR inspections

Should someone call him and let him know to expect the state/district to contact him. I feel the email thing with him is not very productive. I can do it, if you have a name that I can give him David. LMK.

Marcia B Mia, Acting Chief
Air Branch
Office of Compliance
2227A WJCS
U.S. Environmental Protection Agency
202-564-7042

From: Basinger, David
Sent: Wednesday, May 23, 2018 11:40 AM
To: Marsh, Karen <Marsh.Karen@epa.gov>; Mia, Marcia <Mia.Marcia@epa.gov>
Subject: RE: [External] RE: Method 21/LDAR inspections

I'm fine with you referring him to the state (and/or District). I'll share this with a few others to see if they have anything to add; if they do, I'll pass that along.

From: Marsh, Karen
Sent: Wednesday, May 23, 2018 5:43 AM
To: Mia, Marcia <Mia.Marcia@epa.gov>; Basinger, David <Basinger.David@epa.gov>
Subject: FW: [External] RE: Method 21/LDAR inspections

Marcia and David,

There's been a lot of back and forth with this guy over when calibration is required when using Method 21 at a well site. I finally got some additional information and based on what he is describing below, he appears to only be subject to state and local regulations, and not NSPS OOOOa.

David, is it ok if I refer him to the state for his question? I am also happy to refer him to you but I'm not sure that is appropriate since his question is very clearly about the state and local regs.

Any additional thoughts before I respond?

Karen

****

Karen R. Marsh, PE
US EPA, OAQPS, Sectors Policies and Programs Division
Fuels and Incineration Group
109 TW Alexander Drive, Mail Code E143-05
Research Triangle Park, NC 27711
Direct: (919) 541-1065; email: marsh.karen@epa.gov

From: Enns S (Steve) at Aera [mailto:SJEnns@aeraenergy.com]
Sent: Tuesday, May 22, 2018 3:37 PM
To: Marsh, Karen <Marsh.Karen@epa.gov>
Subject: RE: [External] RE: Method 21/LDAR inspections

If you read the entire email chain, I think it's pretty clear what I'm trying to find out. But, we are an oil and gas production facility with heavy and light oil wells that are steam enhanced. We have PUC quality fuel gas that we purchase and non-PUC quality gas from our casing gas and tank vapor recovery gas. Pretty much all of our wells and gas lines are subject to either the new methane rule, 4409 or 4401 (San Joaquin Valley APCD). All of these rules require LDAR inspections that require Method 21 inspections and calibrations. Method 21 does not specify a calibration frequency. According to Ned, there should be a subpart that describes the frequency of calibrations. I understand that you and Ned both indicated that calibrations need to occur each day that inspections occur, but where does it say that in the regulation? That is all I'm trying to find out. I just need you to point out the rule and section or subpart that says calibrations are required every day that inspections are conducted.

Regarding manufacturers recommendations, I was referring to the manufacturer of the testing equipment. For example, http://www.rkiinstruments.com/pdf/71-0154RK.pdf. RKI industries recommends calibrations every 1 to 3 months (clearly stated on page one).

Any clarification on this would be greatly appreciated.

Thanks,
Steve

From: Marsh, Karen [mailto:Marsh.Karen@epa.gov]
Sent: Tuesday, May 22, 2018 10:25 AM
To: Enns S (Steve) at Aera <SJEnns@aeraenergy.com>
Subject: [External] RE: [External] RE: Method 21/LDAR inspections

Steve,

In an effort to provide the most efficient and appropriate response, I am requesting some additional data. Each response is revealing additional information from you on what your overall question is and why you are asking.

Can you be more specific about the type of facility we are referring to in your question? Are you referring to well sites? Natural gas processing plants? Or some other type of site (please specify)?

I'm not sure which manufacturer information you are referring to regarding calibration. Can you send a link to that so I can review that information for context?

Thanks,
Karen

****

Karen R. Marsh, PE
US EPA, OAQPS, Sectors Policies and Programs Division
Fuels and Incineration Group
109 TW Alexander Drive, Mail Code E143-05
Research Triangle Park, NC 27711
Direct: (919) 541-1065; email: marsh.karen@epa.gov

From: Enns S (Steve) at Aera [mailto:SJEnns@aeraenergy.com]
Sent: Tuesday, May 22, 2018 11:20 AM
To: Marsh, Karen <Marsh.Karen@epa.gov>
Subject: Re: [External] RE: Method 21/LDAR inspections

Thanks for the help on this, but what I'm struggling with is this... Where is the text in the rule that indicates daily calibrations for any LDAR activity? I need that info in order to justify paying our LDAR to do daily calibrations. Manufactures recommendations are monthly, so why do it daily?

On May 22, 2018, at 5:43 AM, Marsh, Karen <Marsh.Karen@epa.gov> wrote:

> Any inspection activity. It is expected that the instrument is calibrated prior to each day of surveying to ensure accuracy of the results.
>
> **********
> Karen R. Marsh, PE
> US EPA, OAQPS, Sectors Policies and Programs Division
> Fuels and Incineration Group
> 109 TW Alexander Drive, Mail Code E143-05
> Research Triangle Park, NC 27711
> Direct: (919) 541-1065; email: marsh.karen@epa.gov
>
> **From:** Enns S (Steve) at Aera [mailto:SJEnns@aeraenergy.com]
> **Sent:** Monday, May 21, 2018 4:26 PM
> **To:** Marsh, Karen <Marsh.Karen@epa.gov>
> **Subject:** RE: Method 21/LDAR inspections
>
> When you say "standard requirements", is that referring to the methane rule only? Or any LDAR inspection activity?
>
> **From:** Marsh, Karen [mailto:Marsh.Karen@epa.gov]
> **Sent:** Friday, May 18, 2018 11:01 AM
> **To:** Enns S (Steve) at Aera <SJEnns@aeraenergy.com>
> **Subject:** [External] RE: Method 21/LDAR inspections
>
> Hi Steve,
>
> Each of the rules you mention should include a requirement for the calibration. It may vary across the rules.
>
> In terms of NSPS OOOOa, you would refer to section 60.5397a(c)(8)(i) and (ii). Those subparagraphs basically point you to Method 21 of Appendix A-7. Unfortunately, it does not look like we included a specific calibration requirement in the fugitive emissions requirements in 60.5397a. However, standard requirements, including the CARB methane rule (section 95669) require calibration prior to any monitoring day and drift checks at the end of the monitoring day or as needed.
>
> I hope this helps.
> Karen
>
> **********
> Karen R. Marsh, PE
> US EPA, OAQPS, Sectors Policies and Programs Division

Fuels and Incineration Group
109 TW Alexander Drive, Mail Code E143-05
Research Triangle Park, NC 27711
Direct: (919) 541-1065; email: marsh.karen@epa.gov

From: Enns S (Steve) at Aera [mailto:SJEnns@aeraenergy.com]
Sent: Friday, May 18, 2018 10:42 AM
To: Marsh, Karen <Marsh.Karen@epa.gov>
Subject: Re: Method 21/LDAR inspections

Karen, if you can't answer my question, please let me know who can.

Thanks, Steve

On May 10, 2018, at 2:13 PM, Enns S (Steve) at Aera <SJEnns@aeraenergy.com> wrote:

> Karen, in Ned's initial response, he says "For most LDAR programs, the appropriate subpart will dictate the appropriate QC, method performance, recordkeeping, etc…"
>
> This is what I need help with, what exactly is the appropriate subpart for my facility (oil and gas production facilities)? I know we are subject to the methane rule, OOOa, and local rules 4409 and 4401. They all reference Method 21. Which subpart will tell me the required frequency of calibrations? I know it's daily, but I want to see it so I can quote the rule and document it on our forms.
>
> Thanks,
> *Steve Enns*
> **CAS - Belridge**
> **Aera Energy LLC**
> Office: (661) 665-7529
> Mobile: (661) 381-3378
> E-Mail: sjenns@aeraenergy.com

> **From:** Shappley, Ned [mailto:Shappley.Ned@epa.gov]
> **Sent:** Thursday, May 10, 2018 1:15 PM
> **To:** Enns S (Steve) at Aera <SJEnns@aeraenergy.com>
> **Cc:** Marsh, Karen <Marsh.Karen@epa.gov>
> **Subject:** [External] RE: Method 21/LDAR inspections
>
> Steve,
>
> I am on the measurement side of the house and am not the person to determine the applicability of your facility. As I stated before, the compliance authorities are delegated with the implementation of these rules and are best suited to handle these questions.
>
> I have included Karen Marsh for the EPA's Sector Policies and Program Division and is the LDAR lead on the rule side, in case she has anything to add.
>
> Best Regards,
> Ned

From: Enns S (Steve) at Aera [mailto:SJEnns@aeraenergy.com]
Sent: Thursday, 10 May, 2018 15:21
To: Shappley, Ned <Shappley.Ned@epa.gov>
Subject: RE: Method 21/LDAR inspections

Wells and tanks. Heavy and light oil/gas. All of our LDAR related rules mention Method 21. No one seems to be able to agree on anything due to the extreme difficulty of reading and comprehending any of the regulations. Give me a call when you can so we can discuss. 661-381-3378

Thanks, Steve

From: Shappley, Ned [mailto:Shappley.Ned@epa.gov]
Sent: Thursday, May 10, 2018 12:07 PM
To: Enns S (Steve) at Aera <SJEnns@aeraenergy.com>
Subject: [External] RE: Method 21/LDAR inspections

Steve,

I am not sure if I can answer this question without knowing more about the effected facility, is this an upstream or downstream facility? Also, you may consider contacting your local regulatory authority (San Joaquin Valley?) to determine if there are any state rules that would apply.

Ned

From: Enns S (Steve) at Aera [mailto:SJEnns@aeraenergy.com]
Sent: Thursday, 10 May, 2018 13:31
To: Shappley, Ned <Shappley.Ned@epa.gov>
Subject: RE: Method 21/LDAR inspections

Ned, subpart VVa refers to the synthetic chemicals manufacturing industry. Is there a subpart specifically for the oil production industry?

Thanks,
Steve

From: Shappley, Ned [mailto:Shappley.Ned@epa.gov]
Sent: Thursday, May 10, 2018 7:07 AM
To: Enns S (Steve) at Aera <SJEnns@aeraenergy.com>
Subject: [External] RE: Method 21/LDAR inspections

Steve,

You are required to do a calibration prior to any survey, the calibration requirement in Section 8.1.2 is a periodic (3-month) precision verification and not a daily check. It is important to realize that the applicable subpart may have calibration requirements that exceed the requirements found in the method, these previsions will supersede the

method requirements. For most LDAR programs, the appropriate subpart will dictate the appropriate QC, method performance, recordkeeping, etc…

For example, below are the calibration requirement found in 40 CFR Part 60 subpart VVa:

§60.485a(b) The owner or operator shall determine compliance with the standards in §§60.482-1a through 60.482-11a, 60.483a, and 60.484a as follows:

(1) Method 21 shall be used to determine the presence of leaking sources. The instrument shall be calibrated before use each day of its use by the procedures specified in Method 21 of appendix A-7 of this part. The following calibration gases shall be used:

(i) Zero air (less than 10 ppm of hydrocarbon in air); and

(ii) A mixture of methane or n-hexane and air at a concentration no more than 2,000 ppm greater than the leak definition concentration of the equipment monitored…… If the monitoring instrument's design allows for multiple calibration scales, then the lower scale shall be calibrated with a calibration gas that is no higher than 2,000 ppm above the concentration specified as a leak, and the highest scale shall be calibrated with a calibration gas that is approximately equal to 10,000 ppm. If only one scale on an instrument will be used during monitoring the owner or operator need not calibrate the scales that will not be used during that day's monitoring.

(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)(7)…..

The Best Practices is very informative and is a good tool to develop a model LDAR program, but it is essential to understand that often time the rule (federal or state) defines how the measurement should be conducted. Regardless of the rule, daily calibrations should always be performed at the start of any working day, after any change to the instrumentation, and after the survey (i.e., drift) to validate the any previous measurement (i.e., survey).

I hope this helpful,

Best Regards,

Ned

From: Enns S (Steve) at Aera [mailto:SJEnns@aeraenergy.com]
Sent: Wednesday, 9 May, 2018 18:23
To: Shappley, Ned <Shappley.Ned@epa.gov>; Garnett, Kim <Garnett.Kim@epa.gov>
Subject: Method 21/LDAR inspections

Hi, I am requesting clarification on what is required regarding calibrations of equipment used for Method 21/LDAR inspections.

Section 8.1.2 requires a calibration precision test every 3 months.

Section 10 refers to another calibration, but doesn't list a frequency. Is this different from 8.1.2? The EPA "Best Practices Guide" says to calibrate before each monitoring

episode, which I assume means every day that the instrument is used. From reading Method 21, it appears that daily calibrations are not required, is that correct?

The guide also says to do a drift check at the end of the day. Since this isn't required by Method 21, I am assuming that the drift check is more of a recommendation. Is that correct?

Steve Enns
CAS - Belridge
Aera Energy LLC
Office: (661) 665-7529
Mobile: (661) 381-3378
E-Mail: sjenns@aeraenergy.com

Message

From: Marsh, Karen [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=03408BEA5D5B4030BE80FA390ED47026-MARSH, KARE]
Sent: 2/22/2018 7:05:32 PM
To: Sorrell, Virginia [Sorrell.Virginia@epa.gov]
CC: North, Alexis [North.Alexis@epa.gov]
Subject: RE: Shut-in well question

Ex. 5 Deliberative Process (DP)

Thanks!
Karen

****

Karen R. Marsh, PE
US EPA, OAQPS, Sectors Policies and Programs Division
Fuels and Incineration Group
109 TW Alexander Drive, Mail Code E143-05
Research Triangle Park, NC 27711
Direct: (919) 541-1065; email: marsh.karen@epa.gov

From: Sorrell, Virginia
Sent: Thursday, February 22, 2018 1:47 PM
To: Marsh, Karen <Marsh.Karen@epa.gov>
Cc: North, Alexis <North.Alexis@epa.gov>
Subject: RE: Shut-in well question

How about this:

Hi all,

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Thanks,
Ginny

Virginia Sorrell
Air Enforcement Division
Office of Civil Enforcement
U.S. Environmental Protection Agency
Phone: 303-312-6669

This email, including attachments, may contain material that is confidential, privileged, and/or attorney work product.

From: Marsh, Karen
Sent: Thursday, February 22, 2018 6:58 AM
To: Sorrell, Virginia <Sorrell.Virginia@epa.gov>
Cc: North, Alexis <North.Alexis@epa.gov>
Subject: RE: Shut-in well question

Thanks Ginny. Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Do you mind drafting something that we can send to the workgroup? Perhaps i Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Thanks again!
Karen

****

Karen R. Marsh, PE
US EPA, OAQPS, Sectors Policies and Programs Division
Fuels and Incineration Group
109 TW Alexander Drive, Mail Code E143-05
Research Triangle Park, NC 27711
Direct: (919) 541-1065; email: marsh.karen@epa.gov

From: Sorrell, Virginia
Sent: Wednesday, February 21, 2018 5:39 PM
To: Marsh, Karen <Marsh.Karen@epa.gov>
Cc: North, Alexis <North.Alexis@epa.gov>
Subject: RE: Shut-in well question

Hi Karen,

Interesting question. Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Alex – did you have other thoughts? Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

If we do want to propose edits to allow for this, I could try to help with that if you'd like.

Thanks,
Ginny

Virginia Sorrell
Air Enforcement Division
Office of Civil Enforcement
U.S. Environmental Protection Agency
Phone: 303-312-6669

This email, including attachments, may contain material that is confidential, privileged, and/or attorney work product.

From: Marsh, Karen
Sent: Wednesday, February 21, 2018 1:35 PM
To: Sorrell, Virginia <Sorrell.Virginia@epa.gov>
Cc: North, Alexis <North.Alexis@epa.gov>
Subject: FW: Shut-in well question

Hi Ginny,

I wanted to reach out to you to see if you had any insights on this topic. We had the following question come in from a consultant.

Is there any guidance on how to handle facilities that are shut-in? Is it expected that you survey anyway or is it acceptable to delay the survey until the sites comes back online?

Alex and I have had some discussions on this and we thought you might be able to offer some insight. We think i Ex. 5 Deliberative Process (DP) Ex. 5 Deliberative Process (DP) but aren't really sure how to address it.

Thoughts?

****
Karen R. Marsh, PE
US EPA, OAQPS, Sectors Policies and Programs Division
Fuels and Incineration Group
109 TW Alexander Drive, Mail Code E143-05
Research Triangle Park, NC 27711
Direct: (919) 541-1065; email: marsh.karen@epa.gov

From: North, Alexis
Sent: Tuesday, February 20, 2018 10:46 AM
To: Marsh, Karen <Marsh.Karen@epa.gov>
Subject: RE: Shut-in well question

Totally makes sense and I think this is a great discussion topic.

Alexis North, Environmental Scientist
Office of Enforcement, Compliance & Environmental Justice
EPA Region 8
1595 Wynkoop Street (8ENF-AT)
Denver, CO 80202-1129
Phone: 303-312-7005
Email: north.alexis@epa.gov

From: Marsh, Karen
Sent: Tuesday, February 20, 2018 8:35 AM
To: North, Alexis <North.Alexis@epa.gov>
Subject: RE: Shut-in well question

Hey Alex,

Can we stick this on the list for tomorrow afternoon's call? Ex. 5 Deliberative Process (DP)
Ex. 5 Deliberative Process (DP) Does that make sense?

****

Karen R. Marsh, PE
US EPA, OAQPS, Sectors Policies and Programs Division
Fuels and Incineration Group
109 TW Alexander Drive, Mail Code E143-05
Research Triangle Park, NC 27711
Direct: (919) 541-1065; email: marsh.karen@epa.gov

From: North, Alexis
Sent: Wednesday, February 14, 2018 2:28 PM
To: Marsh, Karen <Marsh.Karen@epa.gov>
Subject: RE: Shut-in well question

Hi Karen, Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Let me know if you have any further questions or want me to take this to the wider NSPS OOOO/OOOOa group during our call next week.

Thanks,

Alex

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Alexis North, Environmental Scientist
Office of Enforcement, Compliance & Environmental Justice
EPA Region 8
1595 Wynkoop Street (8ENF-AT)
Denver, CO 80202-1129
Phone: 303-312-7005
Email: north.alexis@epa.gov

From: Marsh, Karen
Sent: Monday, February 12, 2018 8:19 AM
To: North, Alexis <North.Alexis@epa.gov>
Subject: RE: Shut-in well question

Thanks Alex. This is helpful and makes sense. I'll wait to respond to the person until you've had a chance to confer with others.

****

Karen R. Marsh, PE
US EPA, OAQPS, Sectors Policies and Programs Division
Fuels and Incineration Group
109 TW Alexander Drive, Mail Code E143-05
Research Triangle Park, NC 27711
Direct: (919) 541-1065; email: marsh.karen@epa.gov

From: North, Alexis
Sent: Friday, February 09, 2018 6:42 PM
To: Marsh, Karen <Marsh.Karen@epa.gov>
Subject: Shut-in well question

Hi Karen,

I'm not ignoring you I promise…

My knee jerk answer is based in r Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Thanks and I'll follow up next week,

Alex

Alexis North, Environmental Scientist
Office of Enforcement, Compliance & Environmental Justice
EPA Region 8
1595 Wynkoop Street (8ENF-AT)
Denver, CO 80202-1129
Phone: 303-312-7005
Email: north.alexis@epa.gov

Message

From: Branning, Amy [Branning.Amy@epa.gov]
Sent: 5/30/2017 5:18:39 PM
To: Simons, Andrew [Simons.Andrew@epa.gov]
CC: Talty, Mark [Talty.Mark@epa.gov]; Thompson, Lisa [Thompson.Lisa@epa.gov]
Subject: RE: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Hi Mark:

Thank you for offering to set up the call. Mine should work.

Some of my ARLO colleagues seem to have issues with the participant code. I have not had that problem. But if there is a problem, try 123456. Thank you and talk to you shortly.

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

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-----Original Message-----
From: Branning, Amy
Sent: Tuesday, May 30, 2017 1:12 PM
To: Simons, Andrew <Simons.Andrew@epa.gov>
Cc: Talty, Mark <Talty.Mark@epa.gov>; Thompson, Lisa <Thompson.Lisa@epa.gov>
Subject: RE: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Hi Andy:

1:30 pm is good. Below is the call in number. I will also send out an invite. Thank you so much.

1(855) 564-1700
Your Seven Digit Conference Extension is: 1104806
Your Participant Code is: 234567

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

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-----Original Message-----
From: Simons, Andrew
Sent: Tuesday, May 30, 2017 1:10 PM
To: Branning, Amy <Branning.Amy@epa.gov>
Cc: Talty, Mark <Talty.Mark@epa.gov>
Subject: RE: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Both Mark and I are available at 1:30, if that time works for you. Not so easy for me to set up a conference line at the moment, so if that's possible that would be great. Alternatively, am reachable at my work number (rolls over to my work cell).

Andrew Simons
Assistant General Counsel for Regulatory Issues Office of General Counsel (MC 2322A) U.S. Environmental Protection Agency

1200 Pennsylvania Ave, NW Washington, DC 20460 Phone (202) 564-3649

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From: Branning, Amy
Sent: Tuesday, May 30, 2017 12:58 PM
To: Simons, Andrew
Cc: Talty, Mark
Subject: RE: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Hi Andy:

I forgot to mention that you can just dial my work number (564-1744) and it will transfer to my flexiplace number.

Also, If it is easier for you to just call me directly when you have a free moment, please go ahead. If I can't answer your questions, I will follow up with my program contact.

I also forgot to thank you for your prompt response and sorry to bother you while you are out.

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

This message may contain sensitive, privileged information covered by the deliberative process, attorney-client and/or attorney work product privileges. If you believe you have received this e-mail in error, please notify me and delete the e-mail immediately.

-----Original Message-----
From: Simons, Andrew
Sent: Tuesday, May 30, 2017 11:52 AM
To: Branning, Amy <Branning.Amy@epa.gov>; Talty, Mark <Talty.Mark@epa.gov>
Cc: Zenick, Elliott <Zenick.Elliott@epa.gov>
Subject: RE: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Amy:
I am unexpectedly out of the office and am trying to plug in when I can. I have a few questions, and I think it would be more efficient if we talked. I'm going to try and participate in a 12 PM conference call but could call you later today. Is there a good time to reach you?
Andy

Andrew Simons
Assistant General Counsel for Regulatory Issues Office of General Counsel (MC 2322A) U.S. Environmental Protection Agency
1200 Pennsylvania Ave, NW Washington, DC 20460 Phone (202) 564-3649

May contain sensitive communication for internal deliberations only, attorney-client communication, attorney work product, and/or enforcement sensitive information. Do not distribute outside EPA or DOJ.

From: Branning, Amy
Sent: Tuesday, May 30, 2017 10:42 AM
To: Simons, Andrew; Talty, Mark
Cc: Zenick, Elliott
Subject: FW: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Hi Andy:

Ex. 5 Attorney Client (AC)

Ex. 5 Attorney Client (AC)

Please let me know if there are any legal issues/concerns with Ex. 5 Attorney Client (AC) Thank you in advance.

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

This message may contain sensitive, privileged information covered by the deliberative process, attorney-client and/or attorney work product privileges. If you believe you have received this e-mail in error, please notify me and delete the e-mail immediately.

From: Thompson, Lisa
Sent: Tuesday, May 30, 2017 10:10 AM
To: Branning, Amy <Branning.Amy@epa.gov>
Subject: FW: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Amy – here are the OMB comments on the propsed stay – I don't think Ex. 5 Attorney Client (AC)
Ex. 5 Attorney Client (AC)

From: Cozzie, David
Sent: Friday, May 26, 2017 1:18 PM
To: Thompson, Lisa <Thompson.Lisa@epa.gov<mailto:Thompson.Lisa@epa.gov>>
Subject: FW: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Peter has sent to Erica to send to Darryl and AEG

From: Szabo, Aaron L. EOP/OMB [mailto:Aaron_L_Szabo@ Ex. 6 Personal Privacy (PP)
Sent: Thursday, May 25, 2017 8:43 PM
To: Cozzie, David <Cozzie.David@epa.gov<mailto:Cozzie.David@epa.gov>>; Tsirigotis, Peter <Tsirigotis.Peter@epa.gov<mailto:Tsirigotis.Peter@epa.gov>>
Cc: Szabo, Aaron L. EOP/OMB <Aaron_L_Szabo@omb.eop.gov<mailto:Aaron_L_Szabo@omb.eop.gov>>; DeBruhl, Brandon F. EOP/OMB <Brandon_F_DeBruhl@omb.eop.gov<mailto:Brandon_F_DeBruhl@omb.eop.gov>>
Subject: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Attached please find the summary of interagency comments under EO 12866 and 13563 for the EPA draft proposed rule entitled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements" (RIN 2060-AT59).

Please let me know if you have any questions.

Aaron L. Szabo
Policy Analyst
Office of Information and Regulatory Affairs Office of Management and Budget
202-395-3621
Aaron_L_Szabo@omb.eop.gov<https://eopowa.whca.mil/owa/redir.aspx?C=G5jxRA7u3s_EW-PzDMmGEMYUVTQu1S_cgt8jLnsowd0fDQSbSMzTCA..&URL=mailto%3aAaron_L_Szabo%40omb.eop.gov>

Message

From: Thompson, Lisa [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=C4FE265551504398A47A9049EBA0AA13-THOMPSON, L]
Sent: 2/21/2018 5:08:52 PM
To: Branning, Amy [Branning.Amy@epa.gov]
Subject: Question about addressing enviro petition in the technical proposal --
Attachments: EDF 1 - Oil and Gas NSPS Reconsideration Petition.pdf

Hi Amy,

I was thinking about your question – Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

My question for you is: Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Thanks in advance,
Lisa

Lisa Thompson
Fuels and Incineration Group
Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
919-541-9775

Message

From: Thompson, Lisa [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=C4FE265551504398A47A9049EBA0AA13-THOMPSON, L]
Sent: 2/2/2018 4:33:39 PM
To: Branning, Amy [Branning.Amy@epa.gov]; Mills, Kathy [Mills.Kathy@epa.gov]; Zenick, Elliott [Zenick.Elliott@epa.gov]
Subject: RE: Emailing - 18-000-1941.pdf
Attachments: AL-18-000-1941v7.docx

Ex. 5 Attorney Client (AC) And DPP

From: Branning, Amy
Sent: Wednesday, January 31, 2018 9:12 AM
To: Thompson, Lisa <Thompson.Lisa@epa.gov>; Mills, Kathy <Mills.Kathy@epa.gov>; Zenick, Elliott <Zenick.Elliott@epa.gov>
Subject: FW: Emailing - 18-000-1941.pdf

Ex. 5 Attorney Client (AC) And DPP

Ex. 5 Attorney Client (AC) And DPP

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

This message may contain sensitive, privileged information covered by the deliberative process, attorney-client and/or attorney work product privileges. If you believe you have received this e-mail in error, please notify me and delete the e-mail immediately.

From: Thompson, Lisa
Sent: Monday, January 29, 2018 12:00 PM
To: Branning, Amy <Branning.Amy@epa.gov>; Mills, Kathy <Mills.Kathy@epa.gov>
Subject: RE: Emailing - 18-000-1941.pdf

Amy,

Let us know if this updated response addresses your concerns.

Thanks!
Lisa

From: Branning, Amy
Sent: Wednesday, January 24, 2018 3:29 PM
To: Thompson, Lisa <Thompson.Lisa@epa.gov>; Mills, Kathy <Mills.Kathy@epa.gov>
Subject: RE: Emailing - 18-000-1941.pdf

Ex. 5 Attorney Client (AC) And DPP

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

This message may contain sensitive, privileged information covered by the deliberative process, attorney-client and/or attorney work product privileges. If you believe you have received this e-mail in error, please notify me and delete the e-mail immediately.

From: Thompson, Lisa
Sent: Wednesday, January 24, 2018 2:47 PM
To: Branning, Amy <Branning.Amy@epa.gov>; Mills, Kathy <Mills.Kathy@epa.gov>
Subject: RE: Emailing - 18-000-1941.pdf

Ex. 5 Attorney Client (AC) And DPP

From: Branning, Amy
Sent: Wednesday, January 24, 2018 2:36 PM
To: Thompson, Lisa <Thompson.Lisa@epa.gov>; Mills, Kathy <Mills.Kathy@epa.gov>
Subject: FW: Emailing - 18-000-1941.pdf

Lisa:

Ex. 5 Attorney Client (AC)

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

This message may contain sensitive, privileged information covered by the deliberative process, attorney-client and/or attorney work product privileges. If you believe you have received this e-mail in error, please notify me and delete the e-mail immediately.

From: Thompson, Lisa
Sent: Wednesday, January 24, 2018 2:19 PM
To: Branning, Amy <Branning.Amy@epa.gov>
Cc: Mills, Kathy <Mills.Kathy@epa.gov>
Subject: FW: Emailing - 18-000-1941.pdf

Amy,

Can you review our response to this incoming letter? Let me know if OGC has any objections!

Thanks,
Lisa

From: Mills, Kathy
Sent: Wednesday, January 24, 2018 1:17 PM
To: Davis, Alison <Davis.Alison@epa.gov>; Cozzie, David <Cozzie.David@epa.gov>; Thompson, Lisa <Thompson.Lisa@epa.gov>

Cc: Terry, Sara <Terry.Sara@epa.gov>; Ashley, Jackie <Ashley.Jackie@epa.gov>
Subject: RE: Emailing - 18-000-1941.pdf

David/Lisa,
The most recent version(1941v3) for this response was sent to you both on 1/16 for approval and includes Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

KB

Kathy "KB Mills ~ SPPD ~ U. S. EPA, OAQPS ~ 919-541-1599

From: Davis, Alison
Sent: Wednesday, January 24, 2018 12:58 PM
To: Cozzie, David <Cozzie.David@epa.gov>; Thompson, Lisa <Thompson.Lisa@epa.gov>; Mills, Kathy <Mills.Kathy@epa.gov>
Cc: Terry, Sara <Terry.Sara@epa.gov>; Ashley, Jackie <Ashley.Jackie@epa.gov>
Subject: RE: Emailing - 18-000-1941.pdf

Ex. 5 Deliberative Process (DP)

From: Cozzie, David
Sent: Wednesday, January 24, 2018 12:54 PM
To: Thompson, Lisa <Thompson.Lisa@epa.gov>; Mills, Kathy <Mills.Kathy@epa.gov>; Davis, Alison <Davis.Alison@epa.gov>
Subject: Fwd: Emailing - 18-000-1941.pdf

Have we responded to a similar letter?

Sent from my iPhone

Begin forwarded message:

> **From:** "StClair, Aimee" <StClair.Aimee@epa.gov>
> **Date:** January 24, 2018 at 11:24:14 AM EST
> **To:** "Cozzie, David" <Cozzie.David@epa.gov>
> **Cc:** "Dunkins, Robin" <Dunkins.Robin@epa.gov>
> **Subject: Emailing - 18-000-1941.pdf**
>
> Hi David,
>
> Would this be your control? New one in CMS. Please let me know if yours and who will take lead. The due date says 12/11/17 so not sure why we got this so late.
>
> Thanks,
> Aimee

Message

From: Weitz, Melissa [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=14738D4EA92E4A79B3AB2A96CBB3F5B7-MWEITZ02]
Sent: 2/7/2018 9:54:23 PM
To: Waltzer, Suzanne [Waltzer.Suzanne@epa.gov]
Subject: Fw: For your review: Oil and Gas Policy Proposal - Options Selection Presentation
Attachments: OG Early Guidance Briefing 12_15_17.pptx

I talked to Lisa this afternoon and she mentioned that you had called her about the Friday briefing also. The latest is below.

From: Weitz, Melissa
Sent: Wednesday, February 7, 2018 4:53 PM
To: Gunning, Paul
Subject: Re: For your review: Oil and Gas Policy Proposal - Options Selection Presentation

OAQPS expects that the Friday meeting will be canceled, but the meeting is still on calendars.

If the Friday meeting does happen, OAQPS is planning Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

From: Weitz, Melissa
Sent: Wednesday, February 7, 2018 4:32 PM
To: Gunning, Paul
Subject: Re: For your review: Oil and Gas Policy Proposal - Options Selection Presentation

My understanding was that the Friday meeting was canceled. I'm rechecking with OAQPS.

From: Gunning, Paul
Sent: Wednesday, February 7, 2018 3:26 PM
To: Weitz, Melissa
Subject: RE: For your review: Oil and Gas Policy Proposal - Options Selection Presentation

Thanks Melissa. Do you know what is being pulled together for the Friday early guidance briefing with the Admin.

United States Environmental Protection Agency

Oil and Gas Sector: NSPS OOOOa Reconsideration

Early Guidance Briefing

December 15, 2017

Agenda

Ex. 5 Deliberative Process (DP)

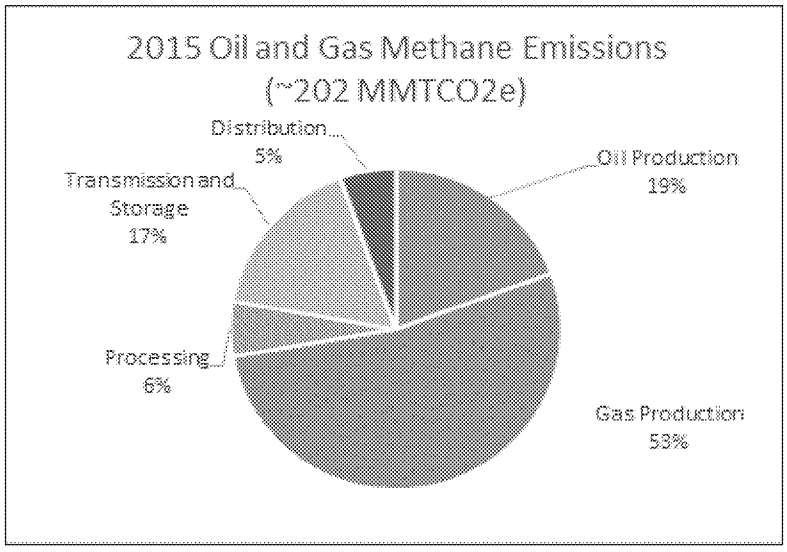
Deliberative – Do Not Cite or Quote

Key Question

Ex. 5 Deliberative Process (DP)

Deliberative – Do Not Cite or Quote

2015 U.S. Methane Emissions: Oil and Gas

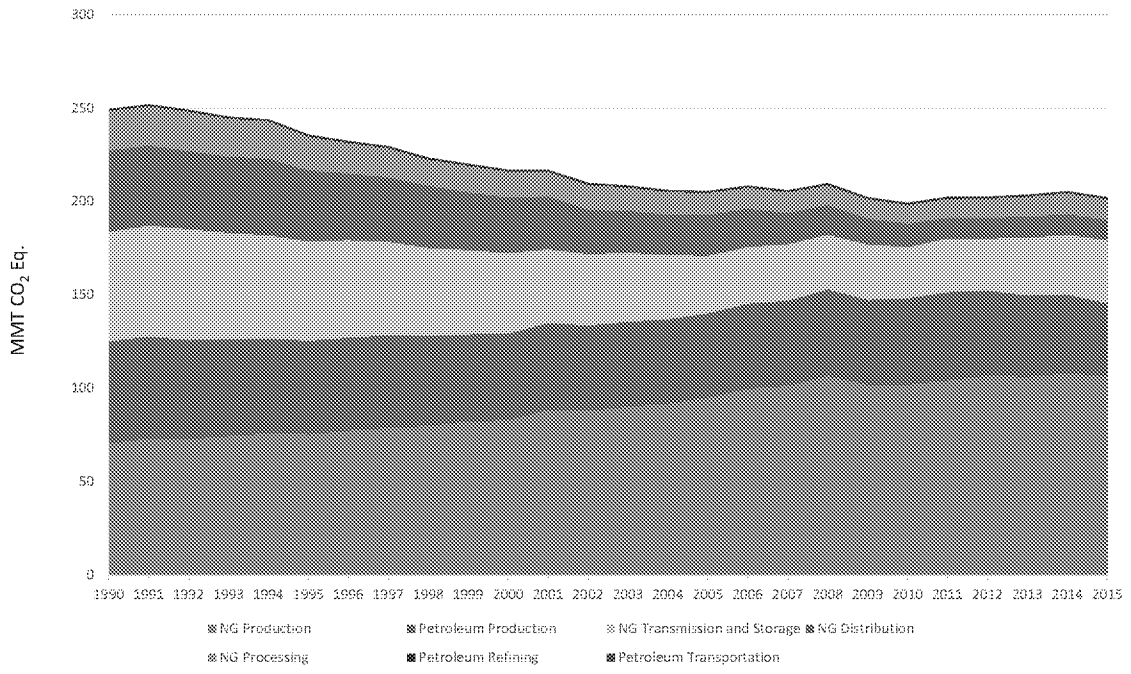


- 30% of total U.S. methane emissions
- 3% of total U.S. greenhouse gas emissions
- 0.5% of global greenhouse gas emissions

Source: 2017 US GHG Inventory

Deliberative – Do Not Cite or Quote

1990-2015 U.S. Methane Emissions: Oil and Gas



Source: 2017 US GHG Inventory

Deliberative – Do Not Cite or Quote

Oil and Gas Sector Overview

Oil Production

- Pneumatic Controllers*
- Storage Tanks*
- Well Completions+
- Fugitive Emissions+
- Pneumatic Pumps+

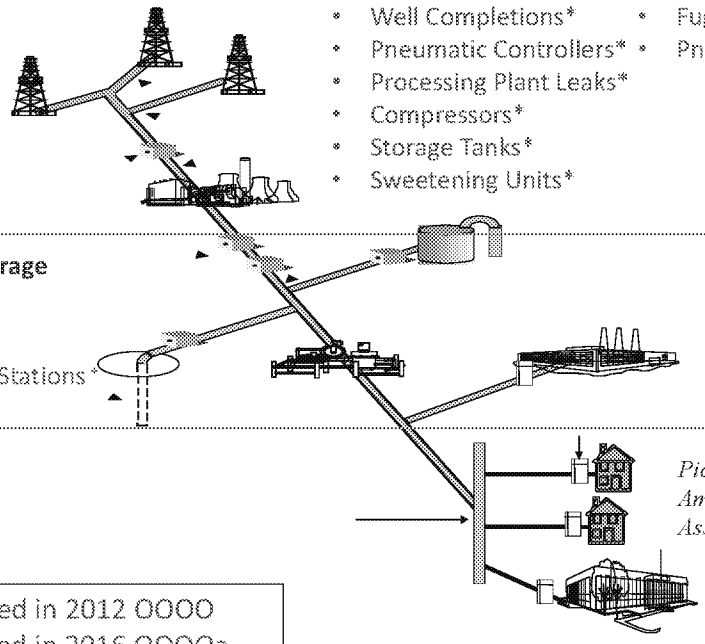
Natural Gas Production & Processing

- Well Completions*
- Pneumatic Controllers*
- Processing Plant Leaks*
- Compressors*
- Storage Tanks*
- Sweetening Units*
- Fugitive Emissions+
- Pneumatic Pumps+

Gas Transmission and Storage

- Storage Tanks*
- Compressors+
- Leaks from Compressor Stations+
- Controllers+

Gas Distribution



Picture courtesy of American Gas Association

*New sources covered in 2012 OOOO
+ New sources covered in 2016 OOOOa

Deliberative – Do Not Cite or Quote

Regulatory Background

- In 2012, EPA issued NSPS OOOO
  - Regulated VOC emissions
- In 2016, EPA issued NSPS OOOOa
  - Regulated greenhouse gases (GHG) in the form of methane
  - Included additional equipment: fugitive emissions from well sites and compressor stations, pneumatic pumps and oil well completions
- EPA received five petitions for reconsideration on NSPS OOOOa
  - EPA has granted reconsideration of the rule
  - Concurrent technical effort to address implementation issues
- EPA received nine petitions for judicial review
  - Litigation is held in abeyance
  - Key litigation issues: regulation of methane, scope of the oil and gas source category

Deliberative – Do Not Cite or Quote

Ex. 5 Deliberative Process (DP)

Deliberative – Do Not Cite or Quote

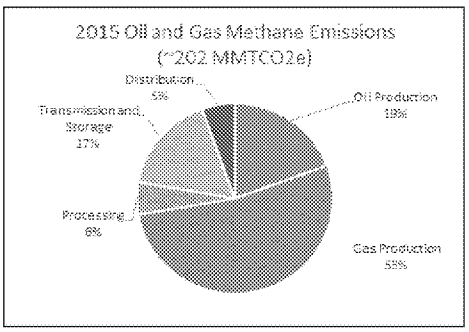
Ex. 5 Deliberative Process (DP)

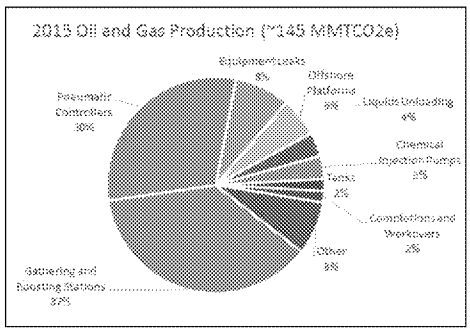
Deliberative – Do Not Cite or Quote

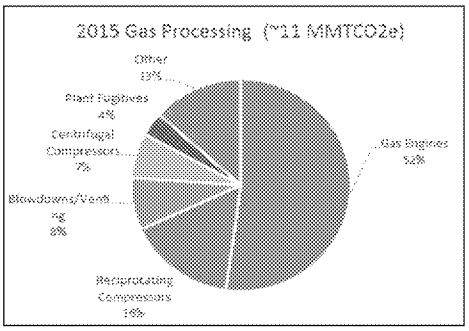
United States
Environmental Protection
Agency

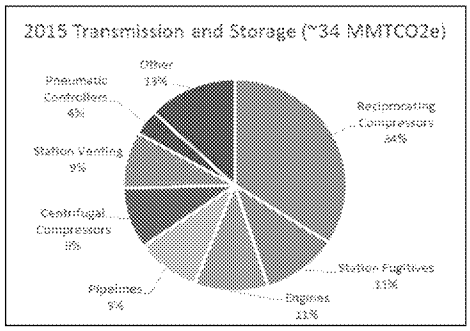
Appendix

2015 U.S. Methane Emissions: Oil and Gas









Source: 2017 US GHG Inventory

Deliberative – Do Not Cite or Quote

Source/Emissions Point	Projected No. of Affected Units For Which Federal Regulations Require Further Action (2016 OOOOa Final RIA) 2018	2025	Total Population[b] (from GHG Inventory) 2015
Well Completions and Recompletions[a]			
Hydraulically Fractured Development Oil Wells	12,000	13,000	
Hydraulically Fractured Wildcat and Delineation Oil Wells	970	1,100	
Total HF oil well completions and recompletions	13,100	14,100	11,526
Fugitive Emissions			
Well Sites	56,000	190,000	503,948
Gathering and Boosting Stations	290	960	5,276
Transmission Compressor Stations	27	90	1,834
Pneumatic Pumps (Well Sites)			
Count of pumps	2,400	7,900	79,806
Pneumatic Controllers (Transmission and Storage)			
Count of high-bleed controllers	290	960	12,090
Reciprocating Compressors (Transmission and Storage)			
Count of reciprocating compressors	96	320	6,710
Centrifugal Compressors (Transmission and Storage)			
Count of wet seal compressors	3	10	838
TOTAL	**72,000**	**220,000**	**622,000**

The table does not include estimated counts of: a) affected facilities in states already regulating those sources, b) facilities with only recordkeeping requirements, or c) replacement or modification of existing sources except for oil well completions and fugitive emissions at well sites. There are several caveats to any comparison, including that the years of data are not comparable (an improved comparison would use projected 2018 and 2025 equipment counts, which are not available at this time).

[a] Well completions are a one-time event so existing sources would not be impacted.

b GHG Inventory counts are total U.S. counts, including equipment that may already be covered by NSPS.

Message

From: Koerber, Mike [Koerber.Mike@epa.gov]
Sent: 3/9/2018 5:43:09 PM
To: Woods, Clint [woods.clint@epa.gov]
Subject: RE: Federal Implementation Plan for Oil and Natural Gas Sources; Uintah and Ouray Indian Reservation in Utah

I'd say NPRM Ex. 5 Deliberative Process (DP)

From: Woods, Clint
Sent: Friday, March 09, 2018 12:37 PM
To: Koerber, Mike <Koerber.Mike@epa.gov>
Subject: FW: Federal Implementation Plan for Oil and Natural Gas Sources; Uintah and Ouray Indian Reservation in Utah

Mike,

We're shooting for NPRM Ex. 5 Deliberative Process (DP) Thanks!

Clint

From: Bolen, Brittany
Sent: Friday, March 9, 2018 12:24 PM
To: Woods, Clint <woods.clint@epa.gov>
Subject: RE: Federal Implementation Plan for Oil and Natural Gas Sources; Uintah and Ouray Indian Reservation in Utah

Thanks, Clint. Real quick though – Ex. 5 Deliberative Process (DP) We have until next week to make adjustments. Would you say the date should move up?

From: Woods, Clint
Sent: Friday, March 9, 2018 9:48 AM
To: Bolen, Brittany <bolen.brittany@epa.gov>
Subject: RE: Federal Implementation Plan for Oil and Natural Gas Sources; Uintah and Ouray Indian Reservation in Utah

Brittany,

Here's the latest:

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Clint Woods
Deputy Assistant Administrator
Office of Air and Radiation, U.S. EPA
202.564.6562

From: Bolen, Brittany
Sent: Thursday, March 8, 2018 10:48 AM
To: Woods, Clint <woods.clint@epa.gov>
Subject: FW: Federal Implementation Plan for Oil and Natural Gas Sources; Uintah and Ouray Indian Reservation in Utah

Hey Clint – yesterday's roundtable reminded me of this FIP, and I wanted to make sure you had this background from my folks. No rush, but do you have any updates on this effort?
Thanks,
Brittany

From: Owens, Nicole
Sent: Friday, January 12, 2018 2:47 PM
To: Dravis, Samantha <dravis.samantha@epa.gov>; Bolen, Brittany <bolen.brittany@epa.gov>
Cc: Nickerson, William <Nickerson.William@epa.gov>; Kime, Robin <Kime.Robin@epa.gov>
Subject: Federal Implementation Plan for Oil and Natural Gas Sources; Uintah and Ouray Indian Reservation in Utah

Samantha and Brittany,

Bill and I would like to apprise you of a regulatory issue that is on the horizon and to inquire if you can confirm any of the information below regarding the timing or substance of the FIP for Oil and Gas Sources in the Uintah and Ouray Indian Reservation in Utah.

In summary, Region 8 is planning to send us this proposal soon for submittal to OMB. The rule will be economically significant due to single year capital cost in 2020 of more than $300 million, and annualized costs are likely to be around $70 million. Monetized benefits are also likely to be less than the estimated costs. The Regulatory Agenda shows a projected proposal date of February.

The FIP will address ozone-forming emissions from existing and new and modified oil and natural gas sources on Indian country lands within the Uintah and Ouray Indian Reservation, where ambient ozone levels violate the 2015 ozone NAAQS for human health. While the EPA currently provides for streamlined permitting of new and modified minor oil and natural gas sources in Indian country that applies nationally, that mechanism will no longer be available to such sources if the area is designated nonattainment for the 2015 ozone NAAQS and sources would need to obtain source-specific permits before beginning construction, potentially delaying continued development of oil and natural gas resources on the U&O Reservation.

More information is below. Your confirmation on timing or substance would be appreciated. We can also discuss this at weekly reg, if needed.

Thanks,
Nicole

Additional Background

The Unita Basin in Utah is predominantly tribal land. There are about 10,400 wells in the Unita Basin, about 76% of those are on Indian country lands within the U&O Reservation. The Basin will almost certainly be designated as nonattainment for the 2015 Ozone NAAQS due to winter-time exceedences.

As of 10/3/2016, new minor sources on the U&O Reservation are subject to emissions controls and a streamlined permitting process as per EPA's 2016 National Indian Country Oil and Gas FIP. (The National Indian Country O&G FIP affects only sources in attainment areas and the Reservation is currently classified as in attainment for ozone.) Existing sources on the reservation are not currently controlled.

When (as is likely) the Basin is designated as nonattainment for the 2015 Ozone NAAQS, there are two concerns regarding O&G development on tribal land in the Unita Basin which will need to be addressed by EPA action:

(1) As noted, the National Indian Country O&G FIP provides for streamlined permitting for new minor sources in attainment areas, but has no streamlined permitting for nonattainment areas. Absent a remedy by EPA, all new minor source permitting for the U&O Reservation would be conducted by Region 8 on a cumbersome, source-specific, case-by-case basis. There are two options to authorize streamlined permitting once the Unita Basin is designated nonattainment, either by amending the National Indian Country O&G FIP to allow streamlined permitting in nonattainment areas as well as attainment areas, or by promulgating a U&O Reservation FIP which includes streamlined permitting.

    The Ute Tribe wrote the Administrator in August supporting the need to amend the National Indian Country O&G FIP, removing the provision that excludes nonattainment areas from its streamlined permitting regime. The Governor of Utah sent the Administrator a similar letter in July. Both the Ute Tribe and Utah favor taking a quick "bridge" action to amend the National Indian Country O&G FIP, to be followed by subsequent action to develop a U&O Reservation FIP to address the regulation of existing sources. Absent this fix, they both state that currently the National Indian Country O&G FIP "discriminates against responsible development".

(2) A FIP will be required to control emissions of all sources (existing and new) to bring ambient levels in the Basin within the NAAQS. The proposed U&O Reservation FIP that will be coming to us shortly includes emissions standards for new minor sources beyond what is required in the National Indian Country O&G FIP, adding controls for three additional types of equipment and processes; the additional controls are intended to create regulatory consistency between the state and tribal land. The U&O Reservation FIP will also include emissions standards for existing minor sources that will mirror these revised new minor source standards. (The proposed FIP includes OOOOa standards for pneumatic pumps and fugitive emissions. Both of these standards appear to be included in the recent proposed stays of the 2016 Methane Rule.)

The U&O Reservation FIP as currently drafted also contains a streamlined permitting system for new minor sources in a nonattainment area. Region 8 is choosing to use the tribal-specific FIP to address this concern rather than amending the National Indian Country O&G FIP.

CAA §110(a)(2)(C) requires that a state's SIP (or a Federal FIP) provide for the control of emissions and regulation of the modification and construction of any stationary source (including minor sources) to assure that NAAQS are achieved. OAR and Region 8 believe that it is necessary to have a control program for existing sources that reduces ambient concentrations in order to ensure that a new source would not cause or contribute to a NAAQS violation. The 2011 Federal Indian Country NSR rule specifies that the review and approval of new minor sources must not cause or contribute to a NAAQS violation. Hence, the need to promulgate a control program for existing sources concurrent with a streamlined permitting program for new sources.

A previous version of the U&O Reservation FIP was developed in the Obama Administration. It included emission controls for existing sources only, it did not include controls for new sources, nor did it contain streamlined permitting provisions for new sources. The proposed FIP was sent to OMB in June 2016, but never cleared interagency review and was withdrawn from OMB at the beginning of the Trump Administration. The action was formally withdrawn via the Reg Agenda in April. While under review, OMB hosted EO 12866 meetings for both the Ute Tribe and oil producers in the Basin. The oil producers believed the proposed FIP was premature and included provisions that went beyond Utah regulatory requirements (although they were not privy to document under review). The Tribe expressed strong concern regarding the lack of meaningful consultation. They expressed substantive concerns regarding the absence of a streamlined permitting process and that the FIP was not tailored to the unique needs of the U&O Reservation. (Region 8 later said that there has been meaningful contact at the staff level between EPA and the Tribe, although that may not have been communicated to senior Tribal decisionmakers.) The cost of the previous version of the FIP and the current version are roughly similar, both in 2020 capital cost and annualized cost. The annualized benefits of the previous version were based on the Obama Administration's Social Cost of Methane and ranged from $40 million to $120 million. With the revised Social Cost of Methane, the benefits estimate will be substantially reduced.

Message

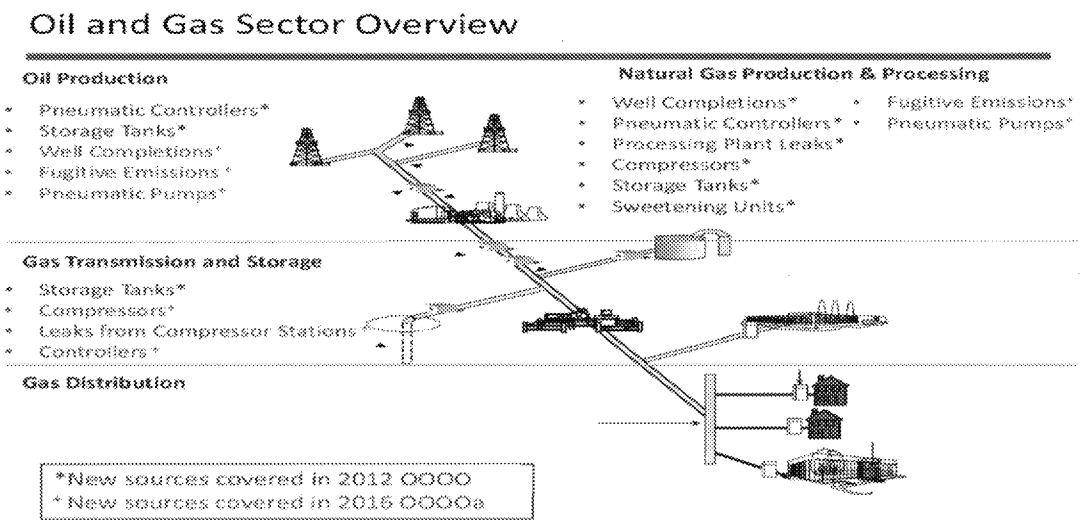
From: Dominguez, Alexander [dominguez.alexander@epa.gov]
Sent: 11/6/2018 4:22:27 PM
To: Woods, Clint [woods.clint@epa.gov]
Subject: QuadOa Background

Here is the background info – Chris has talkers from one/two weeks ago

Oil and Gas NSPS (i.e. Methane Rule)

- In 2012, EPA set a new source performance standard (NSPS) for natural gas wells that are hydraulically fractured. These standards controlled the emission of volatile organic compounds (VOCs) emitted during the production and processing phases.
- In May 2016, EPA expanded the oil and gas requirements setting up a new NSPS to separately control GHGs, which is often referred to as the "methane rule" or "OOOOa". This action expanded the scope of federal authority beyond production and processing to transmission and storage (*see* Image 1 below).
- In early 2017, EPA initiated a reconsideration and review of the 2016 rule, which has been divided into two packages: a technical package and policy package.
- *Technical Package*: In September 2018, EPA proposed targeted improvements to the 2016 rule for the oil and gas industry that streamline implementation, reduce duplicative EPA and state requirements, and significantly decrease unnecessary burdens on domestic energy producers.
    - EPA intends to reconsider certain technical aspects of the fugitive emissions requirements, including monitoring frequency, low production wells, and incorporating emerging technologies and state programs in the alternative means of emissions limitations.
    - EPA also intends to reconsider pneumatic pump standards at well sites and certification requirements of control devices.
    - This technical package is expected to save up to approximately $484 million in regulatory costs from 2019 – 2025 or $75 million annually.
- *Policy Package*: EPA is drafting a policy proposal assessing whether it makes sense to separately regulate methane when control is already effectively achieved in the original OOOO (VOCs only) standard.
    - Further, the industry has undertaken a sophisticated voluntary approach to controlling methane throughout its chain of operation.
    - EPA will also assess whether the entire oil and gas sector should be regulated as one source given significant differences between production/processing and storage/distribution or whether those should be split into separate sources.
    - If the source was split, it is not clear that the relative GHG emissions would be of a high enough threshold to trigger the "significant contribution" criteria that is the statutory prerequisite to setting a performance standard for a covered pollutant under Title I of the Clean Air Act.

Image 1 – Sources Covered in 2012 OOOO and Expansion Under 2016 OOOOa



Message

From: Branning, Amy [Branning.Amy@epa.gov]
Sent: 6/7/2017 1:09:23 PM
To: Zenick, Elliott [Zenick.Elliott@epa.gov]; Palmer, Karen [Palmer.Karen@epa.gov]
Subject: RE: Methane rule

Hi Karen:

Sorry I have been so busy; Elliott just reminded me that I should give you an update on what is going on. So when you have a chance, give me a call. Thanks.

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

This message may contain sensitive, privileged information covered by the deliberative process, attorney-client and/or attorney work product privileges. If you believe you have received this e-mail in error, please notify me and delete the e-mail immediately.

From: Zenick, Elliott
Sent: Wednesday, June 07, 2017 9:05 AM
To: Jordan, Scott <Jordan.Scott@epa.gov>; Branning, Amy <Branning.Amy@epa.gov>; Mills, Derek <Mills.Derek@epa.gov>
Cc: Bangser, Paul <bangser.paul@epa.gov>; Palmer, Karen <Palmer.Karen@epa.gov>
Subject: RE: Methane rule

Ex. 5 Deliberative Process (DP)

From: Jordan, Scott
Sent: Wednesday, June 7, 2017 9:04 AM
To: Branning, Amy <Branning.Amy@epa.gov>; Mills, Derek <Mills.Derek@epa.gov>
Cc: Bangser, Paul <bangser.paul@epa.gov>; Zenick, Elliott <Zenick.Elliott@epa.gov>
Subject: Re: Methane rule

Amy and Derek -

Ex. 5 Deliberative Process (DP) / ACP

Scott Jordan
Air and Radiation Law Office
Office of General Counsel
202-564-7508

From: Bangser, Paul
Sent: Wednesday, June 7, 2017 8:50 AM

To: Jordan, Scott
Subject: Methane rule

Hi Scott,

Ex. 5 Deliberative Process (DP) / ACP

Paul Bangser
Attorney, Office of General Counsel
U.S. Environmental Protection Agency
202-564-5479
bangser.paul@epa.gov

From: Bloomberg BNA [mailto:bloomberg@bna.com]
Sent: Monday, June 05, 2017 4:15 PM
To: Bangser, Paul <bangser.paul@epa.gov>
Subject: June 5 -- Daily Environment Report - Afternoon Briefing

Bloomberg BNA

Daily Environment Report

Afternoon Briefing - Your Preview of Today's News

The following news provides a snapshot of what Bloomberg BNA is working on today. Read the full version of all the stories in the final issue, published each night. The Bloomberg BNA Daily Environment Report is brought to you by EPA Libraries. Please note, these materials may be copyrighted and should not be forwarded outside of the U.S. EPA. If you have any questions or no longer wish to receive these messages, please contact Josue Rivera-Olds at rivera-olds.josue@epa.gov, 202-566-1558.

EPA Taken to Court Over Methane Rule Pause
Posted June 05, 2017, 12:12 P.M. ET
By David Schultz
A coalition of environmental groups is taking the EPA to court over its decision to halt an Obama-era regulation on methane emissions from the oil and gas industry.
The groups, which include the Environmental Defense Fund, Natural Resources Defense Council, and Sierra Club, filed suit in a federal appeals court just days after the Environmental Protection Agency announced it would delay the regulation's upcoming compliance deadlines by at least three months while it weighs whether to repeal the regulation altogether. (The Sierra Club has received funding from Bloomberg Philanthropies, the charitable organization founded

by Michael Bloomberg, founder of Bloomberg L.P. Bloomberg BNA is an affiliate of Bloomberg L.P.)

The regulation, enacted during the Obama administration, requires oil and gas drillers to step up their monitoring for leaking methane, a potent greenhouse gas. The plaintiffs in the lawsuit want the appeals court to overturn the EPA's delay of the regulation's upcoming deadlines. (Clean Air Council v. Pruitt, D.C. Cir., No. 17-01145, 6/5/17.)

EPA 'Safer Choice' Label Program, Criteria Under Fire

Posted June 05, 2017, 7:30 A.M. ET

By Pat Rizzuto

Does a detergent that Procter & Gamble Co. makes merit a 'safer' label designation? The issue has re-ignited a debate among trade association executives over the type of analysis needed to justify such labels.

Some sections of the chemical industry would like to see the Environmental Protection Agency adopt a risk-based approach that would consider additional factors when determining what products qualify for a Safer Choice label. However, other business voices and environmental advocates have voiced opposition to such a move, which one chemical industry specialist said could lead to endless debates over chemical risk estimates.

The debate over the EPA's approach to reviewing products occurs as continued funding for the Safer Choice program is uncertain: the White House's fiscal year 2018 budget request would zero out funding for those activities.

Three CEOs recently discussed the future of the Safer Choice program, a voluntary initiative through which companies can demonstrate that their products are made with chemicals that are safer or more environmentally-friendly than alternatives. Companies seek the Safer Choice label to show customers that there are eco-friendly, less toxic household products on the market.

"Chemicals in commerce should be assessed based on their risk and exposure," Cal Dooley, president and CEO of the American Chemistry Council said May 18 during the Consumer Specialty Products Association's mid-year meeting. "We will consistently oppose any assessment of chemicals that is based on a hazard-only approach," he said.

The CEO for another trade association and chemical policy specialists from environmental and labor groups argued that hazard-based approaches present clear criteria consumers can trust.

A hazard-based approach looks only at the properties of an ingredient, such as the ability of table salt to raise blood pressure. A risk-based approach also would consider the probability that the hazard would happen, taking into consideration factors such as level and frequency of exposure.

Dooley said P&G's Tide® Coldwater detergent is a "classic example" of the problems that arise with hazard-based chemical assessment. The detergent cleans clothes without the need for hot water thereby reducing consumers' energy bills, according to P&G.

Despite those environmental benefits, the detergent didn't qualify for the EPA's Safer Choice label because it had two ingredients that posed a greater hazard than are allowed under the program's criteria, Dooley said.

"How is a product like this that is going to reduce energy consumption, reduce greenhouse gas emissions, not a safer choice for the environment?," Dooley said.

Metrics

An EPA spokeswoman confirmed that agency staff spoke with P&G about its detergent in 2007, when the Safer Choice program was called Design for the Environment. The EPA spokeswoman said the company didn't formally apply for the label. All other aspects of the discussions are confidential, she said.

Tracey Long, a P&G spokeswoman, told Bloomberg BNA: "We appreciate programs like Safer Choice. We also see opportunities to incorporate a broader array of environmental metrics into Safer Choice that would make it even more informative," she said.

The voluntary Safer Choice program encourages products to achieve certain standards. Safer Choice and its criteria were developed by industry, consumer, environmental, and labor groups in partnership with the EPA to encourage use of chemicals that are the safest available for the function they perform in a product.

The standards updated in 2015, for example, encourage "the use of energy-saving technologies including the use of concentrates and detergents that work in cold water." The program also requires products that bear the Safer Choice label to meet certain "master criteria."

All chemical ingredients, regardless of their percentage in the product, are examined. Each ingredient must meet specific, measurable targets that attest to its lack of or reduced

carcinogenicity, reproductive/developmental toxicity, toxicity to aquatic life, and persistence in the environment, EPA's website says.
Chemicals known or expected to cause cancer in people, for example, would not be allowed in a product carrying a Safer Choice label.

Adding Risk to the Equation

The Consumer Specialty Products Association supports the Safer Choice program, Steve Caldeira, president and CEO of that association, told Bloomberg BNA.
"Our member companies have made significant investments in the program which now has over 2,000 brands and 500 companies participating," he said following the mid-year meeting.
The program fosters innovation and competition among companies and benefits consumers but could benefit by adding more flexibility such as adding risk to its criteria, Caldeira said.
Risk-based chemical analyses, for example, could allow Safer Choice labeling to be based on a wider spectrum of chemicals' health and environmental effects than may be possible through the hazard-based toxicity and environmental effects criteria currently used, Caldeira said.

`Magic' With Numbers

Charlotte Brody, vice president of health initiatives for the BlueGreen Alliance, told Bloomberg BNA the program could start losing support from environmental and labor groups if it moved towards a risk-based approach.
"Hazard gives us a more science-based framework that is less likely to be gamed," Brody said.
Using risk-based methods could mean "we would very quickly move away from good science and move to estimates of estimates of estimates," Brody said.
"We could spend 10 years arguing about how much of a dangerous chemical is too much," Brody said. "When we start arguing how much is too much we move away from good science and move to magic with numbers—that's what's important about safer choice—clear criteria."

Consumers' Trust

If industry groups were to convince the Trump administration to move away from the compromises industries and advocacy organizations reached as they crafted Safer Choice, Brody said advocacy groups would start telling consumers the program could no longer be trusted.
"I imagine that not only we at BlueGreen, but all the greens at the table would move away and advertise that we think [Safer Choice] would be meaningless," Brody said.
David Levine, co-founder and CEO of the American Sustainable Business Council, said the cleaning product, clothing, food and other manufacturing companies that have joined the council "pay attention to what consumers are looking for, and one of those things is clarity in the market place."
"Safer Choice has set guidelines that have earned trust of consumers," Levine said.
Reducing energy consumption as cold water detergents do, is great, he said. "Companies should be investing in that, and investing in safer chemistries."
However, Levine said, Safer Choice was set up as a chemicals assessment program, not a program to reduce climate risks.
Jennifer McPartland, a health scientist at the Environmental Defense Fund, said it's inappropriate to judge Safer Choice's success by arguing it should have accomplished a goal for which it was never designed.
P&G should be commended for being innovative and designing a cold water detergent that cuts energy use, McPartland said. "It would be even more impressive" if eventually they also can get the ingredients in that product to meet the Safer Choice criteria, she said.

Safer Choice on the Chopping Block

The President's fiscal 2018 budget request would eliminate the EPA's Safer Choice program, because it seeks no funding for the Office of Pollution Prevention and Toxics' pollution prevention work. Other voluntary programs, such as the agency's Energy Star initiative that recognizes appliances and other products that save energy, also are on the chopping block.
"Zeroing out pollution prevention would be a disaster for American businesses," Levine said.
"Increasing numbers of businesses are taking responsibility to make their products more sustainable, and government serves an important role in setting standards and developing credible labels."
Notwithstanding his preference for a risk-based approach to chemical assessment, Caldeira, with the Consumer Specialty Products Association, said it would be a mistake to eliminate the Safer Choice program.

U.K. Doesn't Think Paris Climate Deal Needs to Be Renegotiated

Posted June 05, 2017, 11:22 A.M. ET

By Alex Morales
Prime Minister Theresa May's government doesn't think the Paris climate deal needs to be renegotiated, her spokeswoman said, pitching Britain behind the position held by France, Germany and Italy.
"We don't believe it needs to be renegotiated," government spokeswoman, Alison Donnelly, told reporters in London. "We signed up to it, we remain committed to it."
The comment adds more substance to the U.K. stance, after May last week was criticized by opposition parties and the media for not being firmer in her criticism of President Donald Trump's decision to pull the U.S. out of the agreement.
May's office said last week that she had expressed her "disappointment" to Trump, but stayed silent on his stated desire to renegotiate the deal. By contrast, Germany, France and Italy issued a joint statement in which they said: "we firmly believe that the Paris Agreement cannot be renegotiated."
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Hunt for Trump's Climate Views Like `Chasing Rabbit,' Perry Says
Posted June 05, 2017, 10:42 A.M. ET
By Stephen Stapczynski
News Story
(Bloomberg) --
People shouldn't focus on whether U.S. President Donald Trump believes climate change is real, according to one of his own Cabinet members.
"Those of you that focus on that are chasing a rabbit down a hole," U.S. Energy Secretary Rick Perry said to reporters in Tokyo June 5. "Is the climate changing? Yes. Is man having an impact? Yes," Perry said ahead of attending Clean Energy and Mission Innovation ministerial meetings in Beijing June 6.
While Trump said the U.S. was pulling out of the Paris climate accord, the president never stated his personal view about whether climate change is man-made. Speculation on his beliefs about climate change is a deflection by opponents who ignore ongoing U.S. leadership and innovation to lower emissions, Perry said.
Trump said he would withdraw the U.S. from the Paris agreement because it favored other nations, a move seen as an opening for China to burnish its image as a global leader on the environment. Business leaders have warned pulling the U.S. from the deal could put the country at a disadvantage in the race to develop and deploy clean-energy technology.
Perry challenged China to compete with U.S. energy technology, insisting that America isn't backing away from its position as a leader in cleaning up the environment.
"I hope China will step in and attempt to take the mantle away" from the U.S., Perry told reporters June 5 in Tokyo. "It would be a good challenge for them."
Perry also visited the wrecked Fukushima Dai-Ichi nuclear plant north of Tokyo June 4 and pledged American support for cleaning up the reactors, which melted down in 2011. He is scheduled to be in Beijing June 6, where he will meet with the world's biggest polluter and other nations and discuss the benefits of nuclear power, liquefied natural gas and renewables.
"Those that would say, 'well you created this void where China is going to take over' —no, we're not stepping back and we haven't created a void," Perry said. "The United States is not backing down from its role as a leader in cleaning up the planet."
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Retail Industry Seeks EPA Answers on Hazardous Waste
Posted June 05, 2017, 7:00 A.M. ET
By Sylvia Carignan
The retail industry is still waiting for the EPA to address a fundamental question: When does a product become waste?
The current state of confusion over the issue adds to the cost of the delivery, processing and handling of hundreds of thousands of different kinds of consumer goods that could be hazardous waste, such as multivitamins, nail polish and light bulbs, industry representatives told Bloomberg BNA.
"If you prematurely call something a waste, then it makes it very difficult for the retail industry to operate the way it does," Noelle Wooten, counsel at Kilpatrick Townsend & Stockton LLP, told Bloomberg BNA. Wooten counsels on chemical, drug packaging, retail and waste management.

It's harder to tell which retail wastes may be regulated by the Resource Conservation and Recovery Act as compared to industrial waste, which seems more clear-cut, said Richard Sieg, regulatory counsel for Inmar, a reverse distributor.
The EPA has not responded to Bloomberg BNA's questions on this topic.

Defining Waste

When a product is returned to the store, recalled, or produced in excess, it may become waste if there is no foreseeable sustainable use. Depending on its contents, the product may also be characterized as hazardous waste and then have to meet stricter disposal requirements.
"There's a disproportionate burden on retailers, especially when you consider the effect on human health and the environment," he said in a D.C. Bar event in May, referring to potential risks of consumer products that could be considered hazardous waste.
Reverse distributors generally accept those products and mark them for disposal or connect with suppliers and vendors who determine where the products could be used. Wooten estimates that the majority of goods sent to reverse distributors find sustainable uses.
But, the burden of answering the waste question, and navigating differences in each state's hazardous waste programs, falls to reverse distributors and retailers.

Filling Gaps

The EPA made a formal request for hazardous waste information from the retail industry in 2014, asking how much waste it generates, how employees are trained in hazardous waste handling, and what their reverse logistical practices are.
The agency released a strategy in 2016 acknowledging some of the issues the retail industry may face when seeking to comply with the Resource Conservation and Recovery Act.
"EPA recognizes that, although there are areas within the program that work well, RCRA regulations may not always be the best fit for the retail sector," the document states.
The EPA also recognizes that hazardous waste determinations differ from small businesses to big box retailers and department stores such as Lowe's, Target, and Macy's.
According to the strategy, the EPA "intends to develop a policy that addresses the reverse distribution process for the retail sector as a whole."
Stericycle Environmental Solutions manages waste, including retail products. Wade Scheel, director of safety, health and compliance for Stericycle, said in a statement that the company sees opportunities for the agency to fill gaps in regulation of aerosol disposal, electronics disposal and the management of certain nicotine products.
The EPA is also working on a rule specifically for pharmaceutical waste.
"Hopefully, the administration will continue with these efforts to continue to provide relief to this unique waste generator sector," Scheel said.

Syngenta Faces 7,000 Kansas Farmers in Dispute Over Modified Corn

Posted June 05, 2017, 11:00 A.M. ET
By Margaret Cronin Fisk and Jef Feeley

Farmers have to deal with threats to their crops from nature all the time. Thousands of Kansans argue, however, that Syngenta AG posed an even bigger threat by failing to prevent its genetically modified corn seed from contaminating U.S. crops, which led to a devastating rejection of imports by Chinese officials.
More than 7,000 Kansas farmers were going to trial June 5 to convince a jury the agricultural giant rushed the genetically engineered seed to market before getting import approval from China, which then stopped shipments saying the corn had been contaminated (Syngenta AG MIR 162 Corn Litigation, D. Kan., No.14-md-02591, 6/5/17).
That move, and the farmers' inability to regain a foothold in China once other countries filled the void, depressed corn prices for years, their suit claims. They are seeking $200 million in lost sales, plus punitive damages.
Syngenta, which denies any wrongdoing and says its genetically modified seed wasn't responsible for price drops, almost went to trial over similar claims in April. A federal court in Minnesota had to reschedule those proceedings after it failed to seat a jury. Several other trials are coming up, including class actions, as lawyers pursue suits on behalf of some 350,000 corn growers claiming as much as $13 billion in losses.

Full Circle

In a twist, the lawsuit spurred by the Chinese action comes as state-owned China National Chemical Corp. is finalizing its $43 billion acquisition of Basel, Switzerland-based Syngenta. A win for the farmers over Syngenta's sales of the seeds would circle back to the Chinese government that rejected the grain.

Judge John Lungstrum, of the U.S. District Court for the District of Kansas, who is overseeing the trial and most of the litigation, has certified eight statewide classes so far and had said he'll set another trial this year. Farmers in 14 additional states are awaiting class certification decisions by the Kansas judge.
Grain exporters Archer-Daniels-Midland Co. and Cargill Inc. have accused Syngenta in separate lawsuits of carelessly allowing its seed to taint U.S. corn, prompting the Chinese rejection. Those suits are pending in state court in Louisiana, with Cargill's headed for trial next year. Syngenta's counterclaims against both companies were dismissed in Kansas last year.
Claims by several individual farmers will be featured as representative of the class in the Kansas City trial. Those farmers are hardly huge agribusinesses, according to their complaint. One of the representatives, David Polifka, planted about 1,000 acres of corn in 2013 and again in 2014 in Gove County, in western Kansas. Another, Charles Frickey, planted about 180 acres of corn in 2012 and 140 acres in 2014 in Decatur County, in the northwestern part of the state.
Insect-Resistant
Syngenta began marketing its Viptera insect-resistant corn in 2011 following U.S. approval the prior year.
The farmers say that Syngenta was reckless both in allowing the trait to contaminate U.S. crops and selling a second GMO seed that also hadn't been approved by China. Syngenta misled the industry on the timing of an expected approval from China, the farmers allege, citing internal company documents and public statements.
In 2012, according to the farmers' complaint, then-chief executive officer Mike Mack told analysts on a conference call that Syngenta expected to have Chinese approval within "a couple of days." Mack did qualify that statement on the call, the company said in court papers, adding at the time that he couldn't "handicap definitively" when China would act.
China didn't approve the trait until 2014, and Syngenta knew that approval wasn't imminent in 2012, the farmers said.
Cratering corn prices cost massive losses to farmers and a chance at a growing market, according to the lawsuit. Even after China approved the seed, prices remained depressed because the country had found new sources for corn, they said.
Syngenta denies misleading the industry and has called the damages claims speculative.
The trials may rise or fall on those claims, said law professor Anthony Sabino, of St. John's University in New York. "It's not enough for these plaintiffs to prove liability," he said.
"For the farmer plaintiffs here, they have to present hard economic facts that prove their market losses," Sabino said. "More than one plaintiff has done a bang-up job of proving liability only to fall flat on proving damages."
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No New Data Needed for Nanomaterials Rule, EPA Official Says
Posted June 05, 2017, 6:01 A.M. ET
By Pat Rizzuto
Companies making and processing nanoengineered chemicals do not have to generate new information to comply with the agency's data collection rule that is effective in August, an EPA manager said.
The rule is the first any federal agency has issued addressing any intentionally engineered nanoscale chemical. BASF SE and the Dow Chemical Co. are among the many chemical manufacturers making nanoengineered chemicals for markets as diverse as aeronautics, electronics, transportation, and sports equipment. "Only report what's in your possession. You don't have to develop surveys or information," Jim Alwood, a manager in the Environmental Protection Agency's new chemicals program, said during a June 1 webinar organized by Semiconductor Equipment and Materials International (SEMI).
The goal of the rule is to get information on chemicals in commerce, Alwood told the global trade association that represents the semiconductor and flat panel display equipment and materials industries. "To manage risks, we need to know which nanoscale materials are in commerce."
"You are just required to submit the information you have. It goes back to what's in commerce and what you know about it," he said. Processors, for example, may not have many specific details about the nanoscale chemical they purchase, but they can tell the agency what they do with it, Alwood said.
Processors mix or otherwise work with a chemical without causing it to transform into other compounds.

Alwood answered questions received during the webinar and questions he said he has heard repeatedly before and after EPA's final rule (RIN: 2070-AJ54) was published in January (82 Fed. Reg. 3641). The agency has delayed the rule's effective date until Aug. 14 (82 Fed. Reg. 22,088).

He encouraged companies to submit more questions by June 15. The agency plans to answer such questions in guidance it announced May 16 (82 Fed. Reg. 22,452).

The rule applies to existing chemicals intentionally designed at the nanoscale—one to 100 nanometers—to have special strength, electrical or other properties they would not have if made in larger dimensions. A human hair is approximately 80,000-100,000 nanometers wide.

Rule's Goals

The rule's goals, Alwood said, are to ensure the EPA knows which nanoengineered chemicals are in commerce and to help the agency decide whether some of those chemicals or some ways companies work with them could pose a risk to workers, the general public or the environment. That information would help the agency decide whether it needs yet more information or if some type of risk management were needed, he said.

Any requests for additional data or regulatory actions would be pursued separately under the normal regulatory notice and comment or other procedures authorized by the Toxic Substances Control Act amendments of 2016, Alwood said.

R&D Generally Exempted

Alwood said he also is hearing many questions about how the rule affects research and development (R&D).

Research involving nanoengineered chemicals is generally exempt from the rule, Alwood said. Companies or other institutions that "manufacture or process, or intend to manufacture or process these chemical substances as part of articles, as impurities, or in small quantities solely for research and development" are exempt, the final rule said.

Michael Castorano of Dow Electronic Materials asked how much a company would have to change a specific nanoengineered chemical before it became a new form of the chemical that the company would have to report.

"You aren't going to need to report every change," Alwood said. The agency wants new information if a company is redesigning a chemical to give it a different size or shape to enable it to function differently than it did, he said.

Eventually, EPA's guidance will be on its website and periodically updated, he said.

N.C. Farm, Owner Fined For Discharging Cow Waste

Posted June 05, 2017, 03:59 P.M. ET

By Andrew M. Ballard

A North Carolina farm and its owner have been sentenced on criminal charges for violating the Clean Water Act by discharging animal waste into a tributary of the French Broad River without a permit.

Asheville, N.C.-based Crowell Farms Inc. and its owner, Michael Alexander Crowell, were fined $40,000 and $10,000, respectively, and given a three-year probationary term by the U.S. District Court for the Western District of North Carolina June 1. Crowell must serve six months of his probationary term under house arrest, and the farm is required to abide by an environmental compliance program for those three years as well (United States v. Crowell Farms Inc., W.D.N.C., No. 1:16-cr-00113, sentencing 6/1/17).

Crowell and his company both pleaded guilty in November 2016 to a single count of violating the Clean Water Act by discharging pollutants without a permit. The defendants' attorney told Bloomberg BNA June 5 that the farm's owner regretted his "poor judgment" and has taken steps to prevent future violations at the cattle farm.

According to federal prosecutors, for at least a few weeks in late 2015, Crowell installed bypasses at the farm's waste lagoons because he was having difficulty with managing the ponds' levels due to rainfall. Crowell's farm, which housed more than 150 cows, only was permitted to discharge liquid waste to an on-site land application system and not directly into bodies of water.

Through the bypass, Crowell illegally discharged the liquid animal waste into a tributary of the French Broad River, which is used as a drinking water source and for recreational purposes and fishing.

"Michael regrets his poor judgment, and since the date of the offense has been working with environmental regulators to make sure nothing like this happens again," according to Stephen L.

Cash, an attorney with the Asheville-based law firm of Cloninger, Barbour, Searson, Jones & Cash who represented the farm and Crowell.
Cash said in an email to Bloomberg BNA that Crowell has never before been convicted of a crime and "is glad to be able to put this matter behind him and glad that he has caused no lasting damage to the French Broad watershed."

Trump's Paris Exit Sidelines D.C. for Danes Blazing Wind Trail

Posted June 05, 2017, 11:21 A.M. ET

By Peter Levring

For Denmark, which relies more on wind energy than any other nation on the planet, June 1 was a pretty bad day.
The country's energy minister, Lars Chr. Lilleholt, watched in dismay as U.S. President Donald Trump extracted the world's biggest economy from the Paris accord, ignoring decades of science-based work that had guided political efforts to protect the globe from climate change.
But Lilleholt says the move also ignored the sound economics of renewable energy, and if the White House isn't listening, he's ready to take his message elsewhere.
The minister's next stop is China, where he'll discuss green energy this week at an event with about 20 other nations (representatives from the U.S. will also be there). Lilleholt says the view in Washington D.C. can't upend a movement that China, India and Europe all support. What's more, he expects American states to ignore Trump's agenda and continue using green energy. He says he's already received signals from local governments to that effect.
"It's my expectation that a number of U.S. states, east-coast states and Texas, among others, will continue to back this," Lilleholt said in an interview in Copenhagen. "Regardless what Trump says, the green transition will continue across the world, and in the U.S."
According to what the Danish government is hearing, Trump is likely to be isolated in his decision to abandon the Paris accord.
The pact still "looks solid," Lilleholt said. "The rest of the world stands together. The EU is united, we've heard from China, India, the U.K. I haven't heard of any other nations preparing to exit."
Lilleholt's travel itinerary sheds some light on the global leadership shift in an area that's proving more economically viable than fossil fuel production. Or, as Columbia University Professor Jeffrey Sachs puts it, Trump's decision to exit the Paris climate accord "is handing industrial leadership outside the U.S."
Denmark, which is home to Vestas Wind Systems A/S, the world's biggest wind-turbine maker, and Dong Energy A/S, the world's biggest offshore wind-park operator, has long played a prominent role in global renewable energy policies.
Vestas estimates that the U.S. wind industry "supports more than 100,000 jobs in 50 states, and it brings billions of dollars in economic development to the communities that host the projects," said Morten Dyrholm, a senior vice president for marketing at the company.
Denmark, which already gets about 40 percent of its electricity from wind power, is on target to have all its energy needs covered by renewables by 2050. Much of the new capacity will be built without subsidies. Lilleholt says Denmark's experience makes clear that coal is no longer cheaper to produce than renewable energy.
Lilleholt says Denmark will lobby hard in the European Union for the bloc to take a bigger role in the Paris accord now that the U.S. is out of the arrangement. He also said it was too much to expect the rest of the world to absorb the gap left by the U.S.
"We can't just distribute the U.S. obligations on 15 percent of the emissions to the other countries," he said.
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How Hard Will Pruitt Crack Down on Lake Erie Farmers?

Posted June 05, 2017, 7:01 A.M. ET

By David Schultz

The business of growing food in the upper Midwest may be about to significantly change.
An agreement reached last year between the U.S. and Canada may force state and federal officials to impose new limits on the amount of fertilizer that can be applied by farmers in parts of Ohio, Indiana, and Michigan. The two countries are seeking to halve the amount of nutrients, mostly from farms, that wash into Lake Erie. High levels of nutrients can cause algae blooms that contaminate the lake, an important drinking water source.
Some Lake Erie farmers have voluntarily adopted measures to reduce their fertilizer use and prevent the erosion of their topsoil. But, depending on how the binational process plays out,

adopting those types of soil conservation measures may no longer become voluntary, something that deeply worries the local agriculture industry.
"Farmers are not big fans of regulation," Joe Cornely, a spokesman with the Ohio Farm Bureau, told Bloomberg BNA. "Decisions are best made locally."

Good Soil's Not Pretty

So what does it look like when a farmer adopts these soil conservation measures? In northwest Ohio, in early spring, one of these fields is not very pretty.
It's cold and wet, and the snowmelt has saturated the soil creating a dark black mud. A week or two before planting season, no one is working in the fields. Instead dead plants—an assortment of partially decomposed radishes, peas, oats and sunflowers—litter the untilled rows.
This farm belongs to Mike Libben, head of the local Soil and Water Conservation District in Ottawa County just outside of Toledo. Libben's farm may not be aesthetically pleasing, but everything he does is geared toward enriching his soil with nutrients and preventing it from washing away.
He's installed more efficient drainage systems that allow him to store water under his fields. He doesn't till his land, because that promotes erosion. And he plants cover crops—the radishes, peas, oats and sunflowers—which hold the soil in place and infuse it with nutrients after they decompose, reducing the need for more fertilizer.
An evangelist for this type of farming, Libben tries to persuade his neighbors through the conservation district to take similar measures. The goal is to reduce the amount of nutrient-laden sediment washing off into Lake Erie, the main source of drinking water for dozens of cities and towns, including Toledo.
Some farmers are receptive, he said, but others are stubbornly immune to his pitches. "It still always comes back to the cost," he told Bloomberg BNA. "'What's the bottom line for me? You want me to spend how many dollars and I don't get anything for it?' But it's the hidden benefits of it."

No Longer Voluntary?

The benefits of soil conservation become more clear when considering what happens when too much fertilizer washes off of farms and drains into Lake Erie. The fertilizer contains nutrients, primarily phosphorus, that are the primary cause of massive algae blooms that have plagued the western part of the lake in recent years.
A large algae bloom can suck all of the oxygen out of the water, creating hypoxic dead-zones where aquatic life can't survive.
And, under certain circumstances, these blooms can release toxins that are hard to detect in drinking water. In the summer of 2014, more than 400,000 residents in and around Toledo were told not to use their taps for three days after the city's water utility was surprised by an algae bloom that formed right in front of its intake pump inside Lake Erie.
Partly spurred on by this incident, the U.S. reached its agreement with Canada last year to reduce the amount of nutrients trickling into Lake Erie by 40 percent.
As a part of the Lake Erie agreement with Canada, which was signed less than a year before the end of the Obama administration, each country has to develop a set of actions to meet the 40 percent nutrient reduction target by February 2018.

Farm Runoff

While nutrients can come from many sources, such as sewers that carry human waste as well as phosphorus-rich detergents away from homes and businesses, farms contribute the overwhelming majority that winds up in Lake Erie and other bodies of water. More than 65 percent of the phosphorus in Lake Erie comes from farms, according to the Ohio Sea Grant.
And in northwest Ohio, farmland dominates the landscape. Nearly three quarters of the land that drains into the Maumee River, the largest western tributary into Lake Erie, is used for agriculture, according to the National Center for Water Quality Research.
But if this region has been farmed for generations, why are algae blooms suddenly a problem now? Climate change is one unavoidable reason, Gail Hesse, head of the National Wildlife Federation's Great Lakes program, said.
Lake Erie is the shallowest of the Great Lakes, and the lake is at its shallowest in its western third near Toledo. That means that rising air temperatures can more easily warm the water there, creating optimal conditions for algae growth. Additionally, even though farmers have become more efficient in applying fertilizer over the years, storms have also become more intense, washing more topsoil into the lakes.

Hesse said the Trump administration won't be able to avoid these facts when crafting its plan to get to 40 percent. "There's no way to achieve those targets without putting restrictions on agriculture in the western basin," she told Bloomberg BNA.

Agreement Moving Forward

At first glance, it would seem as if the Environmental Protection Agency, which is responsible for crafting the U.S. action plan, would have little appetite to take measures that dictate to farmers when and how they can apply fertilizer.

The new administration has consistently staked out pro-business positions on nearly every environmental issue and the agency's new leader, Scott Pruitt, was lauded with three standing ovations when he spoke at a Farm Bureau conference shortly after taking office.

But, so far, there's no evidence that the EPA is abandoning the Lake Erie agreement.

Wendy Carney, a deputy director in the EPA's Great Lakes regional office, said the agency is collaborating with the five states in the Lake Erie watershed on to come up with an action plan. She said they're on track to release a draft version this summer and then finalize it before the end of this year, several months ahead of schedule.

"Agricultural runoff is the top priority for management efforts, particularly in the Maumee River basin," Carney told Bloomberg BNA in an email.

Sandra George, one of Carney's counterparts across the border, also said the change in administrations in the U.S. has had no effect on the two countries' work.

"We still meet," George, a program coordinator in Canada's federal environmental agency, told Bloomberg BNA. "We're doing what we need to do."

'Fans of Regulation'

Cornely, the Ohio Farm Bureau spokesman, said he hopes the EPA takes into account all of the action on this issue that's been happening at the state and local levels. As an example, he pointed to the law Ohio Gov. John Kasich (R) signed in 2015 banning the application of fertilizer on frozen or saturated ground, when it's more susceptible to washing away.

Conditions across the Lake Erie watershed, from Toledo in the west to Buffalo in the east, vary so much that a top-down solution to the runoff problem is not feasible, he said.

"If the overall goal is for each of these government subdivisions to reach [a target], it seems to me to let each one of those entities figure out how to get there," Cornely said. "It's pretty rare that a one-size-fits-all regulation works."

But Cornely acknowledged that, if farmers want the EPA to go gentle on them in regulating runoff, they will need to show that they can deal with the problem themselves. This probably will involve more enthusiastic adoption of the kinds of soil conservation measures that Libben is trying to get his neighbors to adopt, he said.

"If you ask for the authority to stay local, it's incumbent upon you to come up with something that works," Cornely said. "Rights come accompanied by responsibility." This story was made possible in part by a fellowship with the Institute for Journalism & Natural Resources.

E-Commerce Boosts Demand for Brownfields Redevelopment

Posted June 05, 2017, 6:31 A.M. ET

By Sylvia Carignan

The e-commerce industry's appetite for warehouse space near major cities is boosting demand for brownfields as well as environmental insurance.

The trend is especially strong in New Jersey, where more than 50 percent of brownfields redevelopment projects are leased for online retail uses, according to commercial real estate firm Jones Lang LaSalle Inc. Other companies investing in brownfields for e-commerce include FedEx Corp., Under Armour Inc., and Wal-Mart Stores Inc.

With the increased demand for brownfields—which are often former industrial or commercial sites with environmental contamination—sites get cleaned up more quickly and can promote local economic growth.

"The demand has never been as high as it's been today," said Robert Kossar, who manages New Jersey operations for Jones Lang LaSalle Inc.

The same is true in other major metropolitan areas, according to Dan French, who is the chief executive officer of Brownfields Listings, which runs an online bulletin board for brownfields sites open for redevelopment and developers looking for sites.

He told Bloomberg BNA the current demand for warehouse space is "historic." "Land availability is getting tight in well developed locations, like say the I-55 corridor here in Chicagoland, but the demand for space just keeps growing," French said, referring to the Chicago metropolitan area. "The consumer isn't slowing down and neither is e-commerce growth, so the buildup will go on."

Growing Insurance Demand

The demand for environmental insurance also has grown in the first half of 2017, said Glynis Priester, national practice leader in the environmental sector at Wells Fargo.
"On the growth front it is kind of a buyer's market, which I think is helping to drive new customers to buying environmental insurance," Priester told Bloomberg BNA. But there is strong interest in New Jersey from clients who are developing brownfields sites into warehouse space and need insurance coverage for environmental liabilities, Priester said.
"We are seeing a lot of developers who, in the past, really didn't have an appetite to acquire properties that were distressed, or saw a lot of contamination," she said. The high demand for real estate has turned that perspective around, despite the increased price of redeveloping a brownfield.
"Because there is such a dearth of available land, and because of the expense of that land, brownfield redevelopment has been the only means of redevelopment for this entire cycle," Kossar told Bloomberg BNA.
Ultimately, French said, brownfields benefit.
"The long-term trends are in place, industrial rents are [higher]," he said, "and it's great news for brownfield sites."

Investing in Brownfields

FedEx and Under Armour have signed leases to build distribution centers at the former Bethlehem Steel mill complex outside Baltimore.
Testing at the former steel mill showed the presence of lead, semi-volatile organic compounds, and polychlorinated biphenyls, among other contaminants. Cleanup efforts are proceeding under Maryland's voluntary cleanup program.
Offshore contamination near the site is being remediated under the Comprehensive Environmental Response, Compensation, and Liability Act, according to Maryland state documents.
According to Jones Lang LaSalle, the incentives for building at that site include a 10-year property tax credit, employment and job tax credits for being in the Chesapeake Enterprise Zone, and incentives from the regional power company.
FedEx chose the brownfield site "primarily because of its ease of access to major highways, proximity to customers' distribution centers and a strong local community workforce for recruiting employees," Meredith Heighington Miller, a spokeswoman for the company, said.
Under Armour referred Bloomberg BNA questions about the site to the developer.
French pushes brownfield owners in less popular markets to make their sites more appealing by preparing their sites for developers to start their work as soon as possible.
"If significant environmental issues need to be resolved, or a brownfield is early in the redevelopment process and not much information is known, then it can take longer than [developers] can afford to wait," he said.

China Is Said to Halt New Electric-Car Production Permits

Posted June 05, 2017, 11:25 A.M. ET
By Bloomberg News

China plans to halt issuing permits to produce electric vehicles pending a review of the policy because of concern additional approvals may lead to a glut in the world's biggest auto market, according to people familiar with the matter.
The National Development and Reform Commission, which oversees new investments in the auto industry, wants to evaluate the program after handing out 15 production licenses since March 2016, said the people, who asked not to be identified because the discussions aren't public. The NDRC didn't immediately respond to a faxed request for comment.
China has identified new-energy vehicles as a strategic emerging industry and aims to boost annual sales of plug-in hybrids and fully electric cars by 10-fold in the next decade. Besides giving generous subsidies for both consumers and manufacturers, the government created a class of permits allowing companies including billionaire Lu Guanqiu's Wanxiang Group and a Volkswagen AG joint venture to produce only electric vehicles, while imposing a moratorium on new capacity for the manufacture of conventional gasoline-run vehicles.
The state support helped China surpass the U.S. in 2015 to become the world's biggest market for new-energy vehicles—comprising electric vehicles, plug-in hybrids and fuel-cell cars. A total of 507,000 such vehicles were sold last year in the country, according to the China Association of Automobile Manufacturers.
While a suspension of new permits may delay plans by companies such as Internet entrepreneur William Li's NIO and Jia Yueting-backed LeEco's electric-car unit that have said

they intend to apply, it may help incumbent electric-car manufacturers including BYD Co. and BAIC Motor Corp. by limiting the number of new entrants to the industry. Volkswagen's joint venture with Anhui Jianghuai Automobile Group Corp. received the 15th license to produce EVs.
To date, newly set up companies in China have announced at least 98 billion yuan ($14 billion) of investments to build electric car factories with a total annual capacity of 2.9 million units a year, or six times the number of plug-ins sold last year, according to data compiled by Bloomberg from company statements.
Apart from Karma Automotive owner Wanxiang Group, other companies that received the permits to manufacture electric vehicles include auto-parts maker Minth Group, car designer Beijing CH-Auto Technology Co., Beijing Electric Vehicle Co., Hangzhou Changjiang Passenger Vehicle Co. and a unit of Chery Automobile Co.
Chinese Premier Li Keqiang said last week the country will stick to its pledges to tackle global warming. President Donald Trump said he would withdraw the U.S. from the Paris climate pact because it favored other nations, a move seen as an opening for China to burnish its image as a global leader on environment issues.
—With assistance from Yan Zhang.
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Daily Environment Report for EPA

Message

From: Branning, Amy [Branning.Amy@epa.gov]
Sent: 5/30/2017 3:57:18 PM
To: Simons, Andrew [Simons.Andrew@epa.gov]; Talty, Mark [Talty.Mark@epa.gov]
CC: Zenick, Elliott [Zenick.Elliott@epa.gov]
Subject: RE: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Yes. And may my program contact join this call as well since she is currently addressing the OMB comments (also in case you have any questions for her)?

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

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-----Original Message-----
From: Simons, Andrew
Sent: Tuesday, May 30, 2017 11:52 AM
To: Branning, Amy <Branning.Amy@epa.gov>; Talty, Mark <Talty.Mark@epa.gov>
Cc: Zenick, Elliott <Zenick.Elliott@epa.gov>
Subject: RE: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Amy:
I am unexpectedly out of the office and am trying to plug in when I can. I have a few questions, and I think it would be more efficient if we talked. I'm going to try and participate in a 12 PM conference call but could call you later today. Is there a good time to reach you?
Andy

Andrew Simons
Assistant General Counsel for Regulatory Issues Office of General Counsel (MC 2322A) U.S. Environmental Protection Agency
1200 Pennsylvania Ave, NW Washington, DC 20460 Phone (202) 564-3649

May contain sensitive communication for internal deliberations only, attorney-client communication, attorney work product, and/or enforcement sensitive information. Do not distribute outside EPA or DOJ.

From: Branning, Amy
Sent: Tuesday, May 30, 2017 10:42 AM
To: Simons, Andrew; Talty, Mark
Cc: Zenick, Elliott
Subject: FW: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Hi Andy:

Ex. 5 AC/AWP/DP

Ex. 5 AC/AWP/DP

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

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From: Thompson, Lisa
Sent: Tuesday, May 30, 2017 10:10 AM
To: Branning, Amy <Branning.Amy@epa.gov>
Subject: FW: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Amy - here are the OMB comments on the propsed stay - I don't think Ex. 5 Attorney Client (AC)

Ex. 5 Attorney Client (AC)

From: Cozzie, David
Sent: Friday, May 26, 2017 1:18 PM
To: Thompson, Lisa <Thompson.Lisa@epa.gov<mailto:Thompson.Lisa@epa.gov>>
Subject: FW: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Peter has sent to Erica to send to Darryl and AEG

From: Szabo, Aaron L. EOP/OMB [mailto:Aaron_L_Szabo@omb.eop.gov]
Sent: Thursday, May 25, 2017 8:43 PM
To: Cozzie, David <Cozzie.David@epa.gov<mailto:Cozzie.David@epa.gov>>; Tsirigotis, Peter <Tsirigotis.Peter@epa.gov<mailto:Tsirigotis.Peter@epa.gov>>
Cc: Szabo, Aaron L. EOP/OMB <Aaron_L_Szabo@omb.eop.gov<mailto:Aaron_L_Szabo@omb.eop.gov>>; DeBruhl, Brandon F. EOP/OMB <Brandon_F_DeBruhl@omb.eop.gov<mailto:Brandon_F_DeBruhl@omb.eop.gov>>
Subject: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Attached please find the summary of interagency comments under EO 12866 and 13563 for the EPA draft proposed rule entitled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements" (RIN 2060-AT59).

Please let me know if you have any questions.

Aaron L. Szabo
Policy Analyst
Office of Information and Regulatory Affairs Office of Management and Budget
202- Ex. 6 Personal Privacy (PP)
Aaron_L_Szabo@omb.eop.gov<https://eopowa.whca.mil/owa/redir.aspx?C=G5jxRA7u3s_EW-PzDMmGEMYUVTQu1S_cgt8jLnsowd0fDQSbSMzTCA..&URL=mailto%3aAaron_L_Szabo%40omb.eop.gov>

Message

From: Simons, Andrew [Simons.Andrew@epa.gov]
Sent: 5/17/2017 3:14:52 PM
To: Zenick, Elliott [Zenick.Elliott@epa.gov]
CC: Koslow, Karin [Koslow.Karin@epa.gov]
Subject: FW: RESPONSE NEEDED TODAY -- RE: Request - in search of info due by May 12 -

FYI – I had responded to Kristi (it looked to me like she was the one with the question). Ex. 5 Deliberative Process (DP)
Ex. 5 Deliberative Process (DP)

Andrew Simons
Assistant General Counsel
Regulatory Issues Practice Group
Office of General Counsel
U.S. Environmental Protection Agency
Tel. 202-564-3649
WJC-N 7522C

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Please consider the environment before printing this email.

From: Simons, Andrew
Sent: Tuesday, May 16, 2017 3:59 PM
To: Smith, Kristi <Smith.Kristi@epa.gov>
Subject: FW: RESPONSE NEEDED TODAY -- RE: Request - in search of info due by May 12 -

Kristi:

I would start with the Ex. 5 Deliberative Process (DP)
Ex. 5 Deliberative Process (DP)

Andy

Andrew Simons
Assistant General Counsel
Regulatory Issues Practice Group
Office of General Counsel
U.S. Environmental Protection Agency
Tel. 202-564-3649
WJC-N 7522C

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Please consider the environment before printing this email.

From: Koslow, Karin
Sent: Tuesday, May 16, 2017 3:01 PM
To: Simons, Andrew <Simons.Andrew@epa.gov>
Subject: FW: RESPONSE NEEDED TODAY -- RE: Request - in search of info due by May 12 -

Andy – please see Elliott's question below. I'm not sure of the best advice to give him, but I bet you are!

Karin Koslow
Deputy Associate General Counsel
Cross-Cutting Issues Law Office
Office of General Counsel
U.S. Environmental Protection Agency
(202) 564-0171
WJC North Room 7358

From: Zenick, Elliott
Sent: Tuesday, May 16, 2017 2:40 PM
To: Smith, Kristi <Smith.Kristi@epa.gov>
Cc: Koslow, Karin <Koslow.Karin@epa.gov>; OGC ARLO MGMT <OGC_ARLO_MGMT@epa.gov>
Subject: Re: RESPONSE NEEDED TODAY -- RE: Request - in search of info due by May 12 -

Karin. **Ex. 5 AC/DP**. Who do we need to talk to?

NSPS\Regional Haze Practice Group
202-564-1822

On May 16, 2017, at 1:55 PM, Smith, Kristi <Smith.Kristi@epa.gov> wrote:

> Karen –
>
> I'm including the relevant ARLO Assistants here as it will be quickest to get it directly from them (which is how Andy usually does this).
>
> They can respond directly to you.
>
> - Kristi
>
> Kristi M. Smith * Assistant General Counsel for the NAAQS Implementation Group * Air & Radiation Law Office * US EPA, Office of General Counsel * smith.kristi@epa.gov * (202) 564-3068 *
>
> CONFIDENTIAL communication for internal deliberations only; may contain deliberative, attorney-client, attorney work product, or otherwise privileged material; do not distribute outside EPA or DOJ.
>
> ---
>
> **From:** Koslow, Karin
> **Sent:** Tuesday, May 16, 2017 1:49 PM
> **To:** Smith, Kristi <Smith.Kristi@epa.gov>
> **Subject:** Request - in search of info due by May 12 -
> **Importance:** High
>
> Hi Kristi – in Gautam's absence, I'm seeking your help in tracking down who the ARLO rep should be for this workgroup. I received responses already for the other OAR groups. I need to submit today.
>
> Thanks!

Karin

OAR

Ex. 5 Deliberative Process (DP)

Karin Koslow
Deputy Associate General Counsel
Cross-Cutting Issues Law Office
Office of General Counsel
U.S. Environmental Protection Agency
(202) 564-0171
WJC North Room 7358

From: Koslow, Karin
Sent: Tuesday, May 02, 2017 1:30 PM
To: Doster, Brian <Doster.Brian@epa.gov>; Lee, Michael <lee.michaelg@epa.gov>; Orlin, David <Orlin.David@epa.gov>; Rodman, Sonja <Rodman.Sonja@epa.gov>; Smith, Kristi <Smith.Kristi@epa.gov>; Zenick, Elliott <Zenick.Elliott@epa.gov>
Subject: Pls respond by May 12 - new tiering list for MAY

I don't know about you, but it feels like we just finished this for April.....

Here's the list for May tierings – thanks in advance for sending me your workgroup representative by COB May 12th.

Thank you,
Karin

OAR

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Karin Koslow

Deputy Associate General Counsel
Cross-Cutting Issues Law Office
Office of General Counsel
U.S. Environmental Protection Agency
(202) 564-0171
WJC North Room 7510B

Message

From: Koslow, Karin [Koslow.Karin@epa.gov]
Sent: 1/9/2018 9:47:37 PM
To: OGC ARLO MGMT [OGC_ARLO_MGMT@epa.gov]
Subject: ACTION - DUE January 16 - January 2018 Tiering List

All – please see five new groups below (and one Tier change as an FYI).

Please send me your workgroup members for the five new groups by COB, Tuesday, January 16.

Thank you!
Karin

Karin Koslow
Deputy Associate General Counsel
Cross-Cutting Issues Law Office
Office of General Counsel
U.S. Environmental Protection Agency
(202) 564-0171
WJC North Room 7358

January 2018 Tiering List

New Tiering:

OAR

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

No Workgroup Specified

New Tier Changes:

OAR

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

New Split Requests:

OAR

Ex. 5 Deliberative Process (DP)

No Workgroup Specified

Message

From: Zenick, Elliott [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=1B2EAA2A560D415FB7C8CE9BB56C7CE5-EZENICK]
Sent: 6/7/2017 1:04:44 PM
To: Jordan, Scott [Jordan.Scott@epa.gov]; Branning, Amy [Branning.Amy@epa.gov]; Mills, Derek [Mills.Derek@epa.gov]
CC: Bangser, Paul [bangser.paul@epa.gov]; Palmer, Karen [Palmer.Karen@epa.gov]
Subject: RE: Methane rule

Ex. 5 Deliberative Process (DP)

From: Jordan, Scott
Sent: Wednesday, June 7, 2017 9:04 AM
To: Branning, Amy <Branning.Amy@epa.gov>; Mills, Derek <Mills.Derek@epa.gov>
Cc: Bangser, Paul <bangser.paul@epa.gov>; Zenick, Elliott <Zenick.Elliott@epa.gov>
Subject: Re: Methane rule

Amy and Derek -

Ex. 5 Deliberative Process (DP) / ACP

Scott Jordan
Air and Radiation Law Office
Office of General Counsel
202-564-7508

From: Bangser, Paul
Sent: Wednesday, June 7, 2017 8:50 AM
To: Jordan, Scott
Subject: Methane rule

Hi Scott,

Ex. 5 Deliberative Process (DP) / ACP

Paul Bangser
Attorney, Office of General Counsel
U.S. Environmental Protection Agency
202-564-5479
bangser.paul@epa.gov

From: Bloomberg BNA [mailto:bloomberg@bna.com]
Sent: Monday, June 05, 2017 4:15 PM

To: Bangser, Paul <bangser.paul@epa.gov>
Subject: June 5 -- Daily Environment Report - Afternoon Briefing

Bloomberg BNA

Daily Environment Report

Afternoon Briefing - Your Preview of Today's News

The following news provides a snapshot of what Bloomberg BNA is working on today. Read the full version of all the stories in the final issue, published each night. The Bloomberg BNA Daily Environment Report is brought to you by EPA Libraries. Please note, these materials may be copyrighted and should not be forwarded outside of the U.S. EPA. If you have any questions or no longer wish to receive these messages, please contact Josue Rivera-Olds at rivera-olds.josue@epa.gov, 202-566-1558.

EPA Taken to Court Over Methane Rule Pause
Posted June 05, 2017, 12:12 P.M. ET
By David Schultz
A coalition of environmental groups is taking the EPA to court over its decision to halt an Obama-era regulation on methane emissions from the oil and gas industry.
The groups, which include the Environmental Defense Fund, Natural Resources Defense Council, and Sierra Club, filed suit in a federal appeals court just days after the Environmental Protection Agency announced it would delay the regulation's upcoming compliance deadlines by at least three months while it weighs whether to repeal the regulation altogether. (The Sierra Club has received funding from Bloomberg Philanthropies, the charitable organization founded by Michael Bloomberg, founder of Bloomberg L.P. Bloomberg BNA is an affiliate of Bloomberg L.P.)
The regulation, enacted during the Obama administration, requires oil and gas drillers to step up their monitoring for leaking methane, a potent greenhouse gas. The plaintiffs in the lawsuit want the appeals court to overturn the EPA's delay of the regulation's upcoming deadlines. (Clean Air Council v. Pruitt, D.C. Cir., No. 17-01145, 6/5/17.)

EPA 'Safer Choice' Label Program, Criteria Under Fire
Posted June 05, 2017, 7:30 A.M. ET
By Pat Rizzuto
Does a detergent that Procter & Gamble Co. makes merit a 'safer' label designation? The issue has re-ignited a debate among trade association executives over the type of analysis needed to justify such labels.
Some sections of the chemical industry would like to see the Environmental Protection Agency adopt a risk-based approach that would consider additional factors when determining what products qualify for a Safer Choice label. However, other business voices and environmental advocates have voiced opposition to such a move, which one chemical industry specialist said could lead to endless debates over chemical risk estimates.
The debate over the EPA's approach to reviewing products occurs as continued funding for the Safer Choice program is uncertain: the White House's fiscal year 2018 budget request would zero out funding for those activities.

Three CEOs recently discussed the future of the Safer Choice program, a voluntary initiative through which companies can demonstrate that their products are made with chemicals that are safer or more environmentally-friendly than alternatives. Companies seek the Safer Choice label to show customers that there are eco-friendly, less toxic household products on the market.
"Chemicals in commerce should be assessed based on their risk and exposure," Cal Dooley, president and CEO of the American Chemistry Council said May 18 during the Consumer Specialty Products Association's mid-year meeting. "We will consistently oppose any assessment of chemicals that is based on a hazard-only approach," he said.
The CEO for another trade association and chemical policy specialists from environmental and labor groups argued that hazard-based approaches present clear criteria consumers can trust.
A hazard-based approach looks only at the properties of an ingredient, such as the ability of table salt to raise blood pressure. A risk-based approach also would consider the probability that the hazard would happen, taking into consideration factors such as level and frequency of exposure.
Dooley said P&G's Tide® Coldwater detergent is a "classic example" of the problems that arise with hazard-based chemical assessment. The detergent cleans clothes without the need for hot water thereby reducing consumers' energy bills, according to P&G.
Despite those environmental benefits, the detergent didn't qualify for the EPA's Safer Choice label because it had two ingredients that posed a greater hazard than are allowed under the program's criteria, Dooley said.
"How is a product like this that is going to reduce energy consumption, reduce greenhouse gas emissions, not a safer choice for the environment?," Dooley said.

Metrics

An EPA spokeswoman confirmed that agency staff spoke with P&G about its detergent in 2007, when the Safer Choice program was called Design for the Environment. The EPA spokeswoman said the company didn't formally apply for the label. All other aspects of the discussions are confidential, she said.
Tracey Long, a P&G spokeswoman, told Bloomberg BNA: "We appreciate programs like Safer Choice. We also see opportunities to incorporate a broader array of environmental metrics into Safer Choice that would make it even more informative," she said.
The voluntary Safer Choice program encourages products to achieve certain standards. Safer Choice and its criteria were developed by industry, consumer, environmental, and labor groups in partnership with the EPA to encourage use of chemicals that are the safest available for the function they perform in a product.
The standards updated in 2015, for example, encourage "the use of energy-saving technologies including the use of concentrates and detergents that work in cold water." The program also requires products that bear the Safer Choice label to meet certain "master criteria."
All chemical ingredients, regardless of their percentage in the product, are examined. Each ingredient must meet specific, measurable targets that attest to its lack of or reduced carcinogenicity, reproductive/developmental toxicity, toxicity to aquatic life, and persistence in the environment, EPA's website says.
Chemicals known or expected to cause cancer in people, for example, would not be allowed in a product carrying a Safer Choice label.

Adding Risk to the Equation

The Consumer Specialty Products Association supports the Safer Choice program, Steve Caldeira, president and CEO of that association, told Bloomberg BNA.
"Our member companies have made significant investments in the program which now has over 2,000 brands and 500 companies participating," he said following the mid-year meeting.
The program fosters innovation and competition among companies and benefits consumers but could benefit by adding more flexibility such as adding risk to its criteria, Caldeira said.
Risk-based chemical analyses, for example, could allow Safer Choice labeling to be based on a wider spectrum of chemicals' health and environmental effects than may be possible through the hazard-based toxicity and environmental effects criteria currently used, Caldeira said.

`Magic' With Numbers

Charlotte Brody, vice president of health initiatives for the BlueGreen Alliance, told Bloomberg BNA the program could start losing support from environmental and labor groups if it moved towards a risk-based approach.
"Hazard gives us a more science-based framework that is less likely to be gamed," Brody said.

Using risk-based methods could mean "we would very quickly move away from good science and move to estimates of estimates of estimates," Brody said.
"We could spend 10 years arguing about how much of a dangerous chemical is too much," Brody said. "When we start arguing how much is too much we move away from good science and move to magic with numbers—that's what's important about safer choice—clear criteria."

Consumers' Trust

If industry groups were to convince the Trump administration to move away from the compromises industries and advocacy organizations reached as they crafted Safer Choice, Brody said advocacy groups would start telling consumers the program could no longer be trusted.
"I imagine that not only we at BlueGreen, but all the greens at the table would move away and advertise that we think [Safer Choice] would be meaningless," Brody said.
David Levine, co-founder and CEO of the American Sustainable Business Council, said the cleaning product, clothing, food and other manufacturing companies that have joined the council "pay attention to what consumers are looking for, and one of those things is clarity in the market place."
"Safer Choice has set guidelines that have earned trust of consumers," Levine said.
Reducing energy consumption as cold water detergents do, is great, he said. "Companies should be investing in that, and investing in safer chemistries."
However, Levine said, Safer Choice was set up as a chemicals assessment program, not a program to reduce climate risks.
Jennifer McPartland, a health scientist at the Environmental Defense Fund, said it's inappropriate to judge Safer Choice's success by arguing it should have accomplished a goal for which it was never designed.
P&G should be commended for being innovative and designing a cold water detergent that cuts energy use, McPartland said. "It would be even more impressive" if eventually they also can get the ingredients in that product to meet the Safer Choice criteria, she said.

Safer Choice on the Chopping Block

The President's fiscal 2018 budget request would eliminate the EPA's Safer Choice program, because it seeks no funding for the Office of Pollution Prevention and Toxics' pollution prevention work. Other voluntary programs, such as the agency's Energy Star initiative that recognizes appliances and other products that save energy, also are on the chopping block.
"Zeroing out pollution prevention would be a disaster for American businesses," Levine said. "Increasing numbers of businesses are taking responsibility to make their products more sustainable, and government serves an important role in setting standards and developing credible labels."
Notwithstanding his preference for a risk-based approach to chemical assessment, Caldeira, with the Consumer Specialty Products Association, said it would be a mistake to eliminate the Safer Choice program.

U.K. Doesn't Think Paris Climate Deal Needs to Be Renegotiated

Posted June 05, 2017, 11:22 A.M. ET
By Alex Morales

Prime Minister Theresa May's government doesn't think the Paris climate deal needs to be renegotiated, her spokeswoman said, pitching Britain behind the position held by France, Germany and Italy.
"We don't believe it needs to be renegotiated," government spokeswoman, Alison Donnelly, told reporters in London. "We signed up to it, we remain committed to it."
The comment adds more substance to the U.K. stance, after May last week was criticized by opposition parties and the media for not being firmer in her criticism of President Donald Trump's decision to pull the U.S. out of the agreement.
May's office said last week that she had expressed her "disappointment" to Trump, but stayed silent on his stated desire to renegotiate the deal. By contrast, Germany, France and Italy issued a joint statement in which they said: "we firmly believe that the Paris Agreement cannot be renegotiated."
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Hunt for Trump's Climate Views Like `Chasing Rabbit,' Perry Says

Posted June 05, 2017, 10:42 A.M. ET
By Stephen Stapczynski

News Story

(Bloomberg) --
People shouldn't focus on whether U.S. President Donald Trump believes climate change is real, according to one of his own Cabinet members.
"Those of you that focus on that are chasing a rabbit down a hole," U.S. Energy Secretary Rick Perry said to reporters in Tokyo June 5. "Is the climate changing? Yes. Is man having an impact? Yes," Perry said ahead of attending Clean Energy and Mission Innovation ministerial meetings in Beijing June 6.
While Trump said the U.S. was pulling out of the Paris climate accord, the president never stated his personal view about whether climate change is man-made. Speculation on his beliefs about climate change is a deflection by opponents who ignore ongoing U.S. leadership and innovation to lower emissions, Perry said.
Trump said he would withdraw the U.S. from the Paris agreement because it favored other nations, a move seen as an opening for China to burnish its image as a global leader on the environment. Business leaders have warned pulling the U.S. from the deal could put the country at a disadvantage in the race to develop and deploy clean-energy technology.
Perry challenged China to compete with U.S. energy technology, insisting that America isn't backing away from its position as a leader in cleaning up the environment.
"I hope China will step in and attempt to take the mantle away" from the U.S., Perry told reporters June 5 in Tokyo. "It would be a good challenge for them."
Perry also visited the wrecked Fukushima Dai-Ichi nuclear plant north of Tokyo June 4 and pledged American support for cleaning up the reactors, which melted down in 2011. He is scheduled to be in Beijing June 6, where he will meet with the world's biggest polluter and other nations and discuss the benefits of nuclear power, liquefied natural gas and renewables.
"Those that would say, 'well you created this void where China is going to take over' —no, we're not stepping back and we haven't created a void," Perry said. "The United States is not backing down from its role as a leader in cleaning up the planet."
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Retail Industry Seeks EPA Answers on Hazardous Waste

Posted June 05, 2017, 7:00 A.M. ET

By Sylvia Carignan

The retail industry is still waiting for the EPA to address a fundamental question: When does a product become waste?
The current state of confusion over the issue adds to the cost of the delivery, processing and handling of hundreds of thousands of different kinds of consumer goods that could be hazardous waste, such as multivitamins, nail polish and light bulbs, industry representatives told Bloomberg BNA.
"If you prematurely call something a waste, then it makes it very difficult for the retail industry to operate the way it does," Noelle Wooten, counsel at Kilpatrick Townsend & Stockton LLP, told Bloomberg BNA. Wooten counsels on chemical, drug packaging, retail and waste management.
It's harder to tell which retail wastes may be regulated by the Resource Conservation and Recovery Act as compared to industrial waste, which seems more clear-cut, said Richard Sieg, regulatory counsel for Inmar, a reverse distributor.
The EPA has not responded to Bloomberg BNA's questions on this topic.

Defining Waste

When a product is returned to the store, recalled, or produced in excess, it may become waste if there is no foreseeable sustainable use. Depending on its contents, the product may also be characterized as hazardous waste and then have to meet stricter disposal requirements.
"There's a disproportionate burden on retailers, especially when you consider the effect on human health and the environment," he said in a D.C. Bar event in May, referring to potential risks of consumer products that could be considered hazardous waste.
Reverse distributors generally accept those products and mark them for disposal or connect with suppliers and vendors who determine where the products could be used. Wooten estimates that the majority of goods sent to reverse distributors find sustainable uses.
But, the burden of answering the waste question, and navigating differences in each state's hazardous waste programs, falls to reverse distributors and retailers.

Filling Gaps

The EPA made a formal request for hazardous waste information from the retail industry in 2014, asking how much waste it generates, how employees are trained in hazardous waste handling, and what their reverse logistical practices are.

The agency released a strategy in 2016 acknowledging some of the issues the retail industry may face when seeking to comply with the Resource Conservation and Recovery Act.
"EPA recognizes that, although there are areas within the program that work well, RCRA regulations may not always be the best fit for the retail sector," the document states.
The EPA also recognizes that hazardous waste determinations differ from small businesses to big box retailers and department stores such as Lowe's, Target, and Macy's.
According to the strategy, the EPA "intends to develop a policy that addresses the reverse distribution process for the retail sector as a whole."
Stericycle Environmental Solutions manages waste, including retail products. Wade Scheel, director of safety, health and compliance for Stericycle, said in a statement that the company sees opportunities for the agency to fill gaps in regulation of aerosol disposal, electronics disposal and the management of certain nicotine products.
The EPA is also working on a rule specifically for pharmaceutical waste.
"Hopefully, the administration will continue with these efforts to continue to provide relief to this unique waste generator sector," Scheel said.

Syngenta Faces 7,000 Kansas Farmers in Dispute Over Modified Corn

Posted June 05, 2017, 11:00 A.M. ET

By Margaret Cronin Fisk and Jef Feeley

Farmers have to deal with threats to their crops from nature all the time. Thousands of Kansans argue, however, that Syngenta AG posed an even bigger threat by failing to prevent its genetically modified corn seed from contaminating U.S. crops, which led to a devastating rejection of imports by Chinese officials.
More than 7,000 Kansas farmers were going to trial June 5 to convince a jury the agricultural giant rushed the genetically engineered seed to market before getting import approval from China, which then stopped shipments saying the corn had been contaminated (Syngenta AG MIR 162 Corn Litigation, D. Kan., No.14-md-02591, 6/5/17).
That move, and the farmers' inability to regain a foothold in China once other countries filled the void, depressed corn prices for years, their suit claims. They are seeking $200 million in lost sales, plus punitive damages.
Syngenta, which denies any wrongdoing and says its genetically modified seed wasn't responsible for price drops, almost went to trial over similar claims in April. A federal court in Minnesota had to reschedule those proceedings after it failed to seat a jury. Several other trials are coming up, including class actions, as lawyers pursue suits on behalf of some 350,000 corn growers claiming as much as $13 billion in losses.

Full Circle

In a twist, the lawsuit spurred by the Chinese action comes as state-owned China National Chemical Corp. is finalizing its $43 billion acquisition of Basel, Switzerland-based Syngenta. A win for the farmers over Syngenta's sales of the seeds would circle back to the Chinese government that rejected the grain.
Judge John Lungstrum, of the U.S. District Court for the District of Kansas, who is overseeing the trial and most of the litigation, has certified eight statewide classes so far and had said he'll set another trial this year. Farmers in 14 additional states are awaiting class certification decisions by the Kansas judge.
Grain exporters Archer-Daniels-Midland Co. and Cargill Inc. have accused Syngenta in separate lawsuits of carelessly allowing its seed to taint U.S. corn, prompting the Chinese rejection. Those suits are pending in state court in Louisiana, with Cargill's headed for trial next year. Syngenta's counterclaims against both companies were dismissed in Kansas last year.
Claims by several individual farmers will be featured as representative of the class in the Kansas City trial. Those farmers are hardly huge agribusinesses, according to their complaint. One of the representatives, David Polifka, planted about 1,000 acres of corn in 2013 and again in 2014 in Gove County, in western Kansas. Another, Charles Frickey, planted about 180 acres of corn in 2012 and 140 acres in 2014 in Decatur County, in the northwestern part of the state.

Insect-Resistant

Syngenta began marketing its Viptera insect-resistant corn in 2011 following U.S. approval the prior year.
The farmers say that Syngenta was reckless both in allowing the trait to contaminate U.S. crops and selling a second GMO seed that also hadn't been approved by China. Syngenta misled the industry on the timing of an expected approval from China, the farmers allege, citing internal company documents and public statements.

In 2012, according to the farmers' complaint, then-chief executive officer Mike Mack told analysts on a conference call that Syngenta expected to have Chinese approval within "a couple of days." Mack did qualify that statement on the call, the company said in court papers, adding at the time that he couldn't "handicap definitively" when China would act.
China didn't approve the trait until 2014, and Syngenta knew that approval wasn't imminent in 2012, the farmers said.
Cratering corn prices cost massive losses to farmers and a chance at a growing market, according to the lawsuit. Even after China approved the seed, prices remained depressed because the country had found new sources for corn, they said.
Syngenta denies misleading the industry and has called the damages claims speculative.
The trials may rise or fall on those claims, said law professor Anthony Sabino, of St. John's University in New York. "It's not enough for these plaintiffs to prove liability," he said.
"For the farmer plaintiffs here, they have to present hard economic facts that prove their market losses," Sabino said. "More than one plaintiff has done a bang-up job of proving liability only to fall flat on proving damages."
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No New Data Needed for Nanomaterials Rule, EPA Official Says

Posted June 05, 2017, 6:01 A.M. ET

By Pat Rizzuto

Companies making and processing nanoengineered chemicals do not have to generate new information to comply with the agency's data collection rule that is effective in August, an EPA manager said.
The rule is the first any federal agency has issued addressing any intentionally engineered nanoscale chemical. BASF SE and the Dow Chemical Co. are among the many chemical manufacturers making nanoengineered chemicals for markets as diverse as aeronautics, electronics, transportation, and sports equipment. "Only report what's in your possession. You don't have to develop surveys or information," Jim Alwood, a manager in the Environmental Protection Agency's new chemicals program, said during a June 1 webinar organized by Semiconductor Equipment and Materials International (SEMI).
The goal of the rule is to get information on chemicals in commerce, Alwood told the global trade association that represents the semiconductor and flat panel display equipment and materials industries. "To manage risks, we need to know which nanoscale materials are in commerce."
"You are just required to submit the information you have. It goes back to what's in commerce and what you know about it," he said. Processors, for example, may not have many specific details about the nanoscale chemical they purchase, but they can tell the agency what they do with it, Alwood said.
Processors mix or otherwise work with a chemical without causing it to transform into other compounds.
Alwood answered questions received during the webinar and questions he said he has heard repeatedly before and after EPA's final rule (RIN: 2070-AJ54) was published in January (82 Fed. Reg. 3641). The agency has delayed the rule's effective date until Aug. 14 (82 Fed. Reg. 22,088).
He encouraged companies to submit more questions by June 15. The agency plans to answer such questions in guidance it announced May 16 (82 Fed. Reg. 22,452).
The rule applies to existing chemicals intentionally designed at the nanoscale—one to 100 nanometers—to have special strength, electrical or other properties they would not have if made in larger dimensions. A human hair is approximately 80,000-100,000 nanometers wide.

Rule's Goals

The rule's goals, Alwood said, are to ensure the EPA knows which nanoengineered chemicals are in commerce and to help the agency decide whether some of those chemicals or some ways companies work with them could pose a risk to workers, the general public or the environment. That information would help the agency decide whether it needs yet more information or if some type of risk management were needed, he said.
Any requests for additional data or regulatory actions would be pursued separately under the normal regulatory notice and comment or other procedures authorized by the Toxic Substances Control Act amendments of 2016, Alwood said.

R&D Generally Exempted

Alwood said he also is hearing many questions about how the rule affects research and development (R&D).

Research involving nanoengineered chemicals is generally exempt from the rule, Alwood said. Companies or other institutions that "manufacture or process, or intend to manufacture or process these chemical substances as part of articles, as impurities, or in small quantities solely for research and development" are exempt, the final rule said.
Michael Castorano of Dow Electronic Materials asked how much a company would have to change a specific nanoengineered chemical before it became a new form of the chemical that the company would have to report.
"You aren't going to need to report every change," Alwood said. The agency wants new information if a company is redesigning a chemical to give it a different size or shape to enable it to function differently than it did, he said.
Eventually, EPA's guidance will be on its website and periodically updated, he said.

N.C. Farm, Owner Fined For Discharging Cow Waste

Posted June 05, 2017, 03:59 P.M. ET

By Andrew M. Ballard

A North Carolina farm and its owner have been sentenced on criminal charges for violating the Clean Water Act by discharging animal waste into a tributary of the French Broad River without a permit.
Asheville, N.C.-based Crowell Farms Inc. and its owner, Michael Alexander Crowell, were fined $40,000 and $10,000, respectively, and given a three-year probationary term by the U.S. District Court for the Western District of North Carolina June 1. Crowell must serve six months of his probationary term under house arrest, and the farm is required to abide by an environmental compliance program for those three years as well (United States v. Crowell Farms Inc., W.D.N.C., No. 1:16-cr-00113, sentencing 6/1/17).
Crowell and his company both pleaded guilty in November 2016 to a single count of violating the Clean Water Act by discharging pollutants without a permit. The defendants' attorney told Bloomberg BNA June 5 that the farm's owner regretted his "poor judgment" and has taken steps to prevent future violations at the cattle farm.
According to federal prosecutors, for at least a few weeks in late 2015, Crowell installed bypasses at the farm's waste lagoons because he was having difficulty with managing the ponds' levels due to rainfall. Crowell's farm, which housed more than 150 cows, only was permitted to discharge liquid waste to an on-site land application system and not directly into bodies of water.
Through the bypass, Crowell illegally discharged the liquid animal waste into a tributary of the French Broad River, which is used as a drinking water source and for recreational purposes and fishing.
"Michael regrets his poor judgment, and since the date of the offense has been working with environmental regulators to make sure nothing like this happens again," according to Stephen L. Cash, an attorney with the Asheville-based law firm of Cloninger, Barbour, Searson, Jones & Cash who represented the farm and Crowell.
Cash said in an email to Bloomberg BNA that Crowell has never before been convicted of a crime and "is glad to be able to put this matter behind him and glad that he has caused no lasting damage to the French Broad watershed."

Trump's Paris Exit Sidelines D.C. for Danes Blazing Wind Trail

Posted June 05, 2017, 11:21 A.M. ET

By Peter Levring

For Denmark, which relies more on wind energy than any other nation on the planet, June 1 was a pretty bad day.
The country's energy minister, Lars Chr. Lilleholt, watched in dismay as U.S. President Donald Trump extracted the world's biggest economy from the Paris accord, ignoring decades of science-based work that had guided political efforts to protect the globe from climate change.
But Lilleholt says the move also ignored the sound economics of renewable energy, and if the White House isn't listening, he's ready to take his message elsewhere.
The minister's next stop is China, where he'll discuss green energy this week at an event with about 20 other nations (representatives from the U.S. will also be there). Lilleholt says the view in Washington D.C. can't upend a movement that China, India and Europe all support. What's more, he expects American states to ignore Trump's agenda and continue using green energy. He says he's already received signals from local governments to that effect.

"It's my expectation that a number of U.S. states, east-coast states and Texas, among others, will continue to back this," Lilleholt said in an interview in Copenhagen. "Regardless what Trump says, the green transition will continue across the world, and in the U.S."
According to what the Danish government is hearing, Trump is likely to be isolated in his decision to abandon the Paris accord.
The pact still "looks solid," Lilleholt said. "The rest of the world stands together. The EU is united, we've heard from China, India, the U.K. I haven't heard of any other nations preparing to exit."
Lilleholt's travel itinerary sheds some light on the global leadership shift in an area that's proving more economically viable than fossil fuel production. Or, as Columbia University Professor Jeffrey Sachs puts it, Trump's decision to exit the Paris climate accord "is handing industrial leadership outside the U.S."
Denmark, which is home to Vestas Wind Systems A/S, the world's biggest wind-turbine maker, and Dong Energy A/S, the world's biggest offshore wind-park operator, has long played a prominent role in global renewable energy policies.
Vestas estimates that the U.S. wind industry "supports more than 100,000 jobs in 50 states, and it brings billions of dollars in economic development to the communities that host the projects," said Morten Dyrholm, a senior vice president for marketing at the company.
Denmark, which already gets about 40 percent of its electricity from wind power, is on target to have all its energy needs covered by renewables by 2050. Much of the new capacity will be built without subsidies. Lilleholt says Denmark's experience makes clear that coal is no longer cheaper to produce than renewable energy.
Lilleholt says Denmark will lobby hard in the European Union for the bloc to take a bigger role in the Paris accord now that the U.S. is out of the arrangement. He also said it was too much to expect the rest of the world to absorb the gap left by the U.S.
"We can't just distribute the U.S. obligations on 15 percent of the emissions to the other countries," he said.
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How Hard Will Pruitt Crack Down on Lake Erie Farmers?

Posted June 05, 2017, 7:01 A.M. ET

By David Schultz

The business of growing food in the upper Midwest may be about to significantly change.
An agreement reached last year between the U.S. and Canada may force state and federal officials to impose new limits on the amount of fertilizer that can be applied by farmers in parts of Ohio, Indiana, and Michigan. The two countries are seeking to halve the amount of nutrients, mostly from farms, that wash into Lake Erie. High levels of nutrients can cause algae blooms that contaminate the lake, an important drinking water source.
Some Lake Erie farmers have voluntarily adopted measures to reduce their fertilizer use and prevent the erosion of their topsoil. But, depending on how the binational process plays out, adopting those types of soil conservation measures may no longer become voluntary, something that deeply worries the local agriculture industry.
"Farmers are not big fans of regulation," Joe Cornely, a spokesman with the Ohio Farm Bureau, told Bloomberg BNA. "Decisions are best made locally."

Good Soil's Not Pretty

So what does it look like when a farmer adopts these soil conservation measures? In northwest Ohio, in early spring, one of these fields is not very pretty.
It's cold and wet, and the snowmelt has saturated the soil creating a dark black mud. A week or two before planting season, no one is working in the fields. Instead dead plants—an assortment of partially decomposed radishes, peas, oats and sunflowers—litter the untilled rows.
This farm belongs to Mike Libben, head of the local Soil and Water Conservation District in Ottawa County just outside of Toledo. Libben's farm may not be aesthetically pleasing, but everything he does is geared toward enriching his soil with nutrients and preventing it from washing away.
He's installed more efficient drainage systems that allow him to store water under his fields. He doesn't till his land, because that promotes erosion. And he plants cover crops—the radishes, peas, oats and sunflowers—which hold the soil in place and infuse it with nutrients after they decompose, reducing the need for more fertilizer.
An evangelist for this type of farming, Libben tries to persuade his neighbors through the conservation district to take similar measures. The goal is to reduce the amount of nutrient-laden

sediment washing off into Lake Erie, the main source of drinking water for dozens of cities and towns, including Toledo.
Some farmers are receptive, he said, but others are stubbornly immune to his pitches. "It still always comes back to the cost," he told Bloomberg BNA. "'What's the bottom line for me? You want me to spend how many dollars and I don't get anything for it?' But it's the hidden benefits of it."

No Longer Voluntary?

The benefits of soil conservation become more clear when considering what happens when too much fertilizer washes off of farms and drains into Lake Erie. The fertilizer contains nutrients, primarily phosphorus, that are the primary cause of massive algae blooms that have plagued the western part of the lake in recent years.
A large algae bloom can suck all of the oxygen out of the water, creating hypoxic dead-zones where aquatic life can't survive.
And, under certain circumstances, these blooms can release toxins that are hard to detect in drinking water. In the summer of 2014, more than 400,000 residents in and around Toledo were told not to use their taps for three days after the city's water utility was surprised by an algae bloom that formed right in front of its intake pump inside Lake Erie.
Partly spurred on by this incident, the U.S. reached its agreement with Canada last year to reduce the amount of nutrients trickling into Lake Erie by 40 percent.
As a part of the Lake Erie agreement with Canada, which was signed less than a year before the end of the Obama administration, each country has to develop a set of actions to meet the 40 percent nutrient reduction target by February 2018.

Farm Runoff

While nutrients can come from many sources, such as sewers that carry human waste as well as phosphorus-rich detergents away from homes and businesses, farms contribute the overwhelming majority that winds up in Lake Erie and other bodies of water. More than 65 percent of the phosphorus in Lake Erie comes from farms, according to the Ohio Sea Grant.
And in northwest Ohio, farmland dominates the landscape. Nearly three quarters of the land that drains into the Maumee River, the largest western tributary into Lake Erie, is used for agriculture, according to the National Center for Water Quality Research.
But if this region has been farmed for generations, why are algae blooms suddenly a problem now? Climate change is one unavoidable reason, Gail Hesse, head of the National Wildlife Federation's Great Lakes program, said.
Lake Erie is the shallowest of the Great Lakes, and the lake is at its shallowest in its western third near Toledo. That means that rising air temperatures can more easily warm the water there, creating optimal conditions for algae growth. Additionally, even though farmers have become more efficient in applying fertilizer over the years, storms have also become more intense, washing more topsoil into the lakes.
Hesse said the Trump administration won't be able to avoid these facts when crafting its plan to get to 40 percent. "There's no way to achieve those targets without putting restrictions on agriculture in the western basin," she told Bloomberg BNA.

Agreement Moving Forward

At first glance, it would seem as if the Environmental Protection Agency, which is responsible for crafting the U.S. action plan, would have little appetite to take measures that dictate to farmers when and how they can apply fertilizer.
The new administration has consistently staked out pro-business positions on nearly every environmental issue and the agency's new leader, Scott Pruitt, was lauded with three standing ovations when he spoke at a Farm Bureau conference shortly after taking office.
But, so far, there's no evidence that the EPA is abandoning the Lake Erie agreement.
Wendy Carney, a deputy director in the EPA's Great Lakes regional office, said the agency is collaborating with the five states in the Lake Erie watershed on to come up with an action plan. She said they're on track to release a draft version this summer and then finalize it before the end of this year, several months ahead of schedule.
"Agricultural runoff is the top priority for management efforts, particularly in the Maumee River basin," Carney told Bloomberg BNA in an email.
Sandra George, one of Carney's counterparts across the border, also said the change in administrations in the U.S. has had no effect on the two countries' work.
"We still meet," George, a program coordinator in Canada's federal environmental agency, told Bloomberg BNA. "We're doing what we need to do."

'Fans of Regulation'

Cornely, the Ohio Farm Bureau spokesman, said he hopes the EPA takes into account all of the action on this issue that's been happening at the state and local levels. As an example, he pointed to the law Ohio Gov. John Kasich (R) signed in 2015 banning the application of fertilizer on frozen or saturated ground, when it's more susceptible to washing away.
Conditions across the Lake Erie watershed, from Toledo in the west to Buffalo in the east, vary so much that a top-down solution to the runoff problem is not feasible, he said.
"If the overall goal is for each of these government subdivisions to reach [a target], it seems to me to let each one of those entities figure out how to get there," Cornely said. "It's pretty rare that a one-size-fits-all regulation works."
But Cornely acknowledged that, if farmers want the EPA to go gentle on them in regulating runoff, they will need to show that they can deal with the problem themselves. This probably will involve more enthusiastic adoption of the kinds of soil conservation measures that Libben is trying to get his neighbors to adopt, he said.
"If you ask for the authority to stay local, it's incumbent upon you to come up with something that works," Cornely said. "Rights come accompanied by responsibility." This story was made possible in part by a fellowship with the Institute for Journalism & Natural Resources.

E-Commerce Boosts Demand for Brownfields Redevelopment

Posted June 05, 2017, 6:31 A.M. ET

By Sylvia Carignan

The e-commerce industry's appetite for warehouse space near major cities is boosting demand for brownfields as well as environmental insurance.
The trend is especially strong in New Jersey, where more than 50 percent of brownfields redevelopment projects are leased for online retail uses, according to commercial real estate firm Jones Lang LaSalle Inc. Other companies investing in brownfields for e-commerce include FedEx Corp., Under Armour Inc., and Wal-Mart Stores Inc.
With the increased demand for brownfields—which are often former industrial or commercial sites with environmental contamination—sites get cleaned up more quickly and can promote local economic growth.
"The demand has never been as high as it's been today," said Robert Kossar, who manages New Jersey operations for Jones Lang LaSalle Inc.
The same is true in other major metropolitan areas, according to Dan French, who is the chief executive officer of Brownfields Listings, which runs an online bulletin board for brownfields sites open for redevelopment and developers looking for sites.
He told Bloomberg BNA the current demand for warehouse space is "historic." "Land availability is getting tight in well developed locations, like say the I-55 corridor here in Chicagoland, but the demand for space just keeps growing," French said, referring to the Chicago metropolitan area. "The consumer isn't slowing down and neither is e-commerce growth, so the buildup will go on."

Growing Insurance Demand

The demand for environmental insurance also has grown in the first half of 2017, said Glynis Priester, national practice leader in the environmental sector at Wells Fargo.
"On the growth front it is kind of a buyer's market, which I think is helping to drive new customers to buying environmental insurance," Priester told Bloomberg BNA. But there is strong interest in New Jersey from clients who are developing brownfields sites into warehouse space and need insurance coverage for environmental liabilities, Priester said.
"We are seeing a lot of developers who, in the past, really didn't have an appetite to acquire properties that were distressed, or saw a lot of contamination," she said. The high demand for real estate has turned that perspective around, despite the increased price of redeveloping a brownfield.
"Because there is such a dearth of available land, and because of the expense of that land, brownfield redevelopment has been the only means of redevelopment for this entire cycle," Kossar told Bloomberg BNA.
Ultimately, French said, brownfields benefit.
"The long-term trends are in place, industrial rents are [higher]," he said, "and it's great news for brownfield sites."

Investing in Brownfields

FedEx and Under Armour have signed leases to build distribution centers at the former Bethlehem Steel mill complex outside Baltimore.

Testing at the former steel mill showed the presence of lead, semi-volatile organic compounds, and polychlorinated biphenyls, among other contaminants. Cleanup efforts are proceeding under Maryland's voluntary cleanup program.
Offshore contamination near the site is being remediated under the Comprehensive Environmental Response, Compensation, and Liability Act, according to Maryland state documents.
According to Jones Lang LaSalle, the incentives for building at that site include a 10-year property tax credit, employment and job tax credits for being in the Chesapeake Enterprise Zone, and incentives from the regional power company.
FedEx chose the brownfield site "primarily because of its ease of access to major highways, proximity to customers' distribution centers and a strong local community workforce for recruiting employees," Meredith Heighington Miller, a spokeswoman for the company, said.
Under Armour referred Bloomberg BNA questions about the site to the developer.
French pushes brownfield owners in less popular markets to make their sites more appealing by preparing their sites for developers to start their work as soon as possible.
"If significant environmental issues need to be resolved, or a brownfield is early in the redevelopment process and not much information is known, then it can take longer than [developers] can afford to wait," he said.

China Is Said to Halt New Electric-Car Production Permits

Posted June 05, 2017, 11:25 A.M. ET

By Bloomberg News

China plans to halt issuing permits to produce electric vehicles pending a review of the policy because of concern additional approvals may lead to a glut in the world's biggest auto market, according to people familiar with the matter.
The National Development and Reform Commission, which oversees new investments in the auto industry, wants to evaluate the program after handing out 15 production licenses since March 2016, said the people, who asked not to be identified because the discussions aren't public. The NDRC didn't immediately respond to a faxed request for comment.
China has identified new-energy vehicles as a strategic emerging industry and aims to boost annual sales of plug-in hybrids and fully electric cars by 10-fold in the next decade. Besides giving generous subsidies for both consumers and manufacturers, the government created a class of permits allowing companies including billionaire Lu Guanqiu's Wanxiang Group and a Volkswagen AG joint venture to produce only electric vehicles, while imposing a moratorium on new capacity for the manufacture of conventional gasoline-run vehicles.
The state support helped China surpass the U.S. in 2015 to become the world's biggest market for new-energy vehicles—comprising electric vehicles, plug-in hybrids and fuel-cell cars. A total of 507,000 such vehicles were sold last year in the country, according to the China Association of Automobile Manufacturers.
While a suspension of new permits may delay plans by companies such as Internet entrepreneur William Li's NIO and Jia Yueting-backed LeEco's electric-car unit that have said they intend to apply, it may help incumbent electric-car manufacturers including BYD Co. and BAIC Motor Corp. by limiting the number of new entrants to the industry. Volkswagen's joint venture with Anhui Jianghuai Automobile Group Corp. received the 15th license to produce EVs.
To date, newly set up companies in China have announced at least 98 billion yuan ($14 billion) of investments to build electric car factories with a total annual capacity of 2.9 million units a year, or six times the number of plug-ins sold last year, according to data compiled by Bloomberg from company statements.
Apart from Karma Automotive owner Wanxiang Group, other companies that received the permits to manufacture electric vehicles include auto-parts maker Minth Group, car designer Beijing CH-Auto Technology Co., Beijing Electric Vehicle Co., Hangzhou Changjiang Passenger Vehicle Co. and a unit of Chery Automobile Co.
Chinese Premier Li Keqiang said last week the country will stick to its pledges to tackle global warming. President Donald Trump said he would withdraw the U.S. from the Paris climate pact because it favored other nations, a move seen as an opening for China to burnish its image as a global leader on environment issues.
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Daily Environment Report for EPA

Message

From: Bangser, Paul [bangser.paul@epa.gov]
Sent: 6/7/2017 1:14:16 PM
To: Branning, Amy [Branning.Amy@epa.gov]
Subject: RE: Methane rule

Ex. 5 Deliberative Process (DP) / ACP

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From: Branning, Amy
Sent: Wednesday, June 07, 2017 9:06 AM
To: Jordan, Scott <Jordan.Scott@epa.gov>; Mills, Derek <Mills.Derek@epa.gov>
Cc: Bangser, Paul <bangser.paul@epa.gov>; Zenick, Elliott <Zenick.Elliott@epa.gov>
Subject: RE: Methane rule

Ex. 5 Deliberative Process (DP)

Amy Huang Branning
EPA Office of General Counsel
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From: Jordan, Scott
Sent: Wednesday, June 07, 2017 9:04 AM
To: Branning, Amy <Branning.Amy@epa.gov>; Mills, Derek <Mills.Derek@epa.gov>
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Subject: Re: Methane rule

Amy and Derek -

Ex. 5 Deliberative Process (DP) / ACP

Scott Jordan
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From: Bangser, Paul
Sent: Wednesday, June 7, 2017 8:50 AM
To: Jordan, Scott
Subject: Methane rule

Hi Scott,

Ex. 5 Deliberative Process (DP) / ACP

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From: Bloomberg BNA [mailto:bloomberg@bna.com]
Sent: Monday, June 05, 2017 4:15 PM
To: Bangser, Paul <bangser.paul@epa.gov>
Subject: June 5 -- Daily Environment Report - Afternoon Briefing

Bloomberg BNA

Daily Environment Report

Afternoon Briefing - Your Preview of Today's News

The following news provides a snapshot of what Bloomberg BNA is working on today. Read the full version of all the stories in the final issue, published each night. The Bloomberg BNA Daily Environment Report is brought to you by EPA Libraries. Please note, these materials may be copyrighted and should not be forwarded outside of the U.S. EPA. If you have any questions or no

longer wish to receive these messages, please contact Josue Rivera-Olds at rivera-olds.josue@epa.gov, 202-566-1558.

EPA Taken to Court Over Methane Rule Pause

Posted June 05, 2017, 12:12 P.M. ET

By David Schultz

A coalition of environmental groups is taking the EPA to court over its decision to halt an Obama-era regulation on methane emissions from the oil and gas industry.

The groups, which include the Environmental Defense Fund, Natural Resources Defense Council, and Sierra Club, filed suit in a federal appeals court just days after the Environmental Protection Agency announced it would delay the regulation's upcoming compliance deadlines by at least three months while it weighs whether to repeal the regulation altogether. (The Sierra Club has received funding from Bloomberg Philanthropies, the charitable organization founded by Michael Bloomberg, founder of Bloomberg L.P. Bloomberg BNA is an affiliate of Bloomberg L.P.)

The regulation, enacted during the Obama administration, requires oil and gas drillers to step up their monitoring for leaking methane, a potent greenhouse gas. The plaintiffs in the lawsuit want the appeals court to overturn the EPA's delay of the regulation's upcoming deadlines. (Clean Air Council v. Pruitt, D.C. Cir., No. 17-01145, 6/5/17.)

EPA 'Safer Choice' Label Program, Criteria Under Fire

Posted June 05, 2017, 7:30 A.M. ET

By Pat Rizzuto

Does a detergent that Procter & Gamble Co. makes merit a 'safer' label designation? The issue has re-ignited a debate among trade association executives over the type of analysis needed to justify such labels.

Some sections of the chemical industry would like to see the Environmental Protection Agency adopt a risk-based approach that would consider additional factors when determining what products qualify for a Safer Choice label. However, other business voices and environmental advocates have voiced opposition to such a move, which one chemical industry specialist said could lead to endless debates over chemical risk estimates.

The debate over the EPA's approach to reviewing products occurs as continued funding for the Safer Choice program is uncertain: the White House's fiscal year 2018 budget request would zero out funding for those activities.

Three CEOs recently discussed the future of the Safer Choice program, a voluntary initiative through which companies can demonstrate that their products are made with chemicals that are safer or more environmentally-friendly than alternatives. Companies seek the Safer Choice label to show customers that there are eco-friendly, less toxic household products on the market.

"Chemicals in commerce should be assessed based on their risk and exposure," Cal Dooley, president and CEO of the American Chemistry Council said May 18 during the Consumer Specialty Products Association's mid-year meeting. "We will consistently oppose any assessment of chemicals that is based on a hazard-only approach," he said.

The CEO for another trade association and chemical policy specialists from environmental and labor groups argued that hazard-based approaches present clear criteria consumers can trust.

A hazard-based approach looks only at the properties of an ingredient, such as the ability of table salt to raise blood pressure. A risk-based approach also would consider the probability that the hazard would happen, taking into consideration factors such as level and frequency of exposure.

Dooley said P&G's Tide® Coldwater detergent is a "classic example" of the problems that arise with hazard-based chemical assessment. The detergent cleans clothes without the need for hot water thereby reducing consumers' energy bills, according to P&G.

Despite those environmental benefits, the detergent didn't qualify for the EPA's Safer Choice label because it had two ingredients that posed a greater hazard than are allowed under the program's criteria, Dooley said.

"How is a product like this that is going to reduce energy consumption, reduce greenhouse gas emissions, not a safer choice for the environment?," Dooley said.

Metrics

An EPA spokeswoman confirmed that agency staff spoke with P&G about its detergent in 2007, when the Safer Choice program was called Design for the Environment. The EPA spokeswoman

said the company didn't formally apply for the label. All other aspects of the discussions are confidential, she said.
Tracey Long, a P&G spokeswoman, told Bloomberg BNA: "We appreciate programs like Safer Choice. We also see opportunities to incorporate a broader array of environmental metrics into Safer Choice that would make it even more informative," she said.
The voluntary Safer Choice program encourages products to achieve certain standards. Safer Choice and its criteria were developed by industry, consumer, environmental, and labor groups in partnership with the EPA to encourage use of chemicals that are the safest available for the function they perform in a product.
The standards updated in 2015, for example, encourage "the use of energy-saving technologies including the use of concentrates and detergents that work in cold water." The program also requires products that bear the Safer Choice label to meet certain "master criteria."
All chemical ingredients, regardless of their percentage in the product, are examined. Each ingredient must meet specific, measurable targets that attest to its lack of or reduced carcinogenicity, reproductive/developmental toxicity, toxicity to aquatic life, and persistence in the environment, EPA's website says.
Chemicals known or expected to cause cancer in people, for example, would not be allowed in a product carrying a Safer Choice label.

Adding Risk to the Equation

The Consumer Specialty Products Association supports the Safer Choice program, Steve Caldeira, president and CEO of that association, told Bloomberg BNA.
"Our member companies have made significant investments in the program which now has over 2,000 brands and 500 companies participating," he said following the mid-year meeting.
The program fosters innovation and competition among companies and benefits consumers but could benefit by adding more flexibility such as adding risk to its criteria, Caldeira said.
Risk-based chemical analyses, for example, could allow Safer Choice labeling to be based on a wider spectrum of chemicals' health and environmental effects than may be possible through the hazard-based toxicity and environmental effects criteria currently used, Caldeira said.

`Magic' With Numbers

Charlotte Brody, vice president of health initiatives for the BlueGreen Alliance, told Bloomberg BNA the program could start losing support from environmental and labor groups if it moved towards a risk-based approach.
"Hazard gives us a more science-based framework that is less likely to be gamed," Brody said.
Using risk-based methods could mean "we would very quickly move away from good science and move to estimates of estimates of estimates," Brody said.
"We could spend 10 years arguing about how much of a dangerous chemical is too much," Brody said. "When we start arguing how much is too much we move away from good science and move to magic with numbers—that's what's important about safer choice—clear criteria."

Consumers' Trust

If industry groups were to convince the Trump administration to move away from the compromises industries and advocacy organizations reached as they crafted Safer Choice, Brody said advocacy groups would start telling consumers the program could no longer be trusted.
"I imagine that not only we at BlueGreen, but all the greens at the table would move away and advertise that we think [Safer Choice] would be meaningless," Brody said.
David Levine, co-founder and CEO of the American Sustainable Business Council, said the cleaning product, clothing, food and other manufacturing companies that have joined the council "pay attention to what consumers are looking for, and one of those things is clarity in the market place."
"Safer Choice has set guidelines that have earned trust of consumers," Levine said.
Reducing energy consumption as cold water detergents do, is great, he said. "Companies should be investing in that, and investing in safer chemistries."
However, Levine said, Safer Choice was set up as a chemicals assessment program, not a program to reduce climate risks.
Jennifer McPartland, a health scientist at the Environmental Defense Fund, said it's inappropriate to judge Safer Choice's success by arguing it should have accomplished a goal for which it was never designed.

P&G should be commended for being innovative and designing a cold water detergent that cuts energy use, McPartland said. "It would be even more impressive" if eventually they also can get the ingredients in that product to meet the Safer Choice criteria, she said.

Safer Choice on the Chopping Block

The President's fiscal 2018 budget request would eliminate the EPA's Safer Choice program, because it seeks no funding for the Office of Pollution Prevention and Toxics' pollution prevention work. Other voluntary programs, such as the agency's Energy Star initiative that recognizes appliances and other products that save energy, also are on the chopping block.

"Zeroing out pollution prevention would be a disaster for American businesses," Levine said. "Increasing numbers of businesses are taking responsibility to make their products more sustainable, and government serves an important role in setting standards and developing credible labels."

Notwithstanding his preference for a risk-based approach to chemical assessment, Caldeira, with the Consumer Specialty Products Association, said it would be a mistake to eliminate the Safer Choice program.

U.K. Doesn't Think Paris Climate Deal Needs to Be Renegotiated

Posted June 05, 2017, 11:22 A.M. ET

By Alex Morales

Prime Minister Theresa May's government doesn't think the Paris climate deal needs to be renegotiated, her spokeswoman said, pitching Britain behind the position held by France, Germany and Italy.

"We don't believe it needs to be renegotiated," government spokeswoman, Alison Donnelly, told reporters in London. "We signed up to it, we remain committed to it."

The comment adds more substance to the U.K. stance, after May last week was criticized by opposition parties and the media for not being firmer in her criticism of President Donald Trump's decision to pull the U.S. out of the agreement.

May's office said last week that she had expressed her "disappointment" to Trump, but stayed silent on his stated desire to renegotiate the deal. By contrast, Germany, France and Italy issued a joint statement in which they said: "we firmly believe that the Paris Agreement cannot be renegotiated."

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Hunt for Trump's Climate Views Like `Chasing Rabbit,' Perry Says

Posted June 05, 2017, 10:42 A.M. ET

By Stephen Stapczynski

News Story

(Bloomberg) --

People shouldn't focus on whether U.S. President Donald Trump believes climate change is real, according to one of his own Cabinet members.

"Those of you that focus on that are chasing a rabbit down a hole," U.S. Energy Secretary Rick Perry said to reporters in Tokyo June 5. "Is the climate changing? Yes. Is man having an impact? Yes," Perry said ahead of attending Clean Energy and Mission Innovation ministerial meetings in Beijing June 6.

While Trump said the U.S. was pulling out of the Paris climate accord, the president never stated his personal view about whether climate change is man-made. Speculation on his beliefs about climate change is a deflection by opponents who ignore ongoing U.S. leadership and innovation to lower emissions, Perry said.

Trump said he would withdraw the U.S. from the Paris agreement because it favored other nations, a move seen as an opening for China to burnish its image as a global leader on the environment. Business leaders have warned pulling the U.S. from the deal could put the country at a disadvantage in the race to develop and deploy clean-energy technology.

Perry challenged China to compete with U.S. energy technology, insisting that America isn't backing away from its position as a leader in cleaning up the environment.

"I hope China will step in and attempt to take the mantle away" from the U.S., Perry told reporters June 5 in Tokyo. "It would be a good challenge for them."

Perry also visited the wrecked Fukushima Dai-Ichi nuclear plant north of Tokyo June 4 and pledged American support for cleaning up the reactors, which melted down in 2011. He is scheduled to be in Beijing June 6, where he will meet with the world's biggest polluter and other nations and discuss the benefits of nuclear power, liquefied natural gas and renewables.

"Those that would say, 'well you created this void where China is going to take over' —no, we're not stepping back and we haven't created a void," Perry said. "The United States is not backing down from its role as a leader in cleaning up the planet."
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Retail Industry Seeks EPA Answers on Hazardous Waste

Posted June 05, 2017, 7:00 A.M. ET

By Sylvia Carignan

The retail industry is still waiting for the EPA to address a fundamental question: When does a product become waste?

The current state of confusion over the issue adds to the cost of the delivery, processing and handling of hundreds of thousands of different kinds of consumer goods that could be hazardous waste, such as multivitamins, nail polish and light bulbs, industry representatives told Bloomberg BNA.

"If you prematurely call something a waste, then it makes it very difficult for the retail industry to operate the way it does," Noelle Wooten, counsel at Kilpatrick Townsend & Stockton LLP, told Bloomberg BNA. Wooten counsels on chemical, drug packaging, retail and waste management.

It's harder to tell which retail wastes may be regulated by the Resource Conservation and Recovery Act as compared to industrial waste, which seems more clear-cut, said Richard Sieg, regulatory counsel for Inmar, a reverse distributor.

The EPA has not responded to Bloomberg BNA's questions on this topic.

Defining Waste

When a product is returned to the store, recalled, or produced in excess, it may become waste if there is no foreseeable sustainable use. Depending on its contents, the product may also be characterized as hazardous waste and then have to meet stricter disposal requirements.

"There's a disproportionate burden on retailers, especially when you consider the effect on human health and the environment," he said in a D.C. Bar event in May, referring to potential risks of consumer products that could be considered hazardous waste.

Reverse distributors generally accept those products and mark them for disposal or connect with suppliers and vendors who determine where the products could be used. Wooten estimates that the majority of goods sent to reverse distributors find sustainable uses.

But, the burden of answering the waste question, and navigating differences in each state's hazardous waste programs, falls to reverse distributors and retailers.

Filling Gaps

The EPA made a formal request for hazardous waste information from the retail industry in 2014, asking how much waste it generates, how employees are trained in hazardous waste handling, and what their reverse logistical practices are.

The agency released a strategy in 2016 acknowledging some of the issues the retail industry may face when seeking to comply with the Resource Conservation and Recovery Act.

"EPA recognizes that, although there are areas within the program that work well, RCRA regulations may not always be the best fit for the retail sector," the document states.

The EPA also recognizes that hazardous waste determinations differ from small businesses to big box retailers and department stores such as Lowe's, Target, and Macy's.

According to the strategy, the EPA "intends to develop a policy that addresses the reverse distribution process for the retail sector as a whole."

Stericycle Environmental Solutions manages waste, including retail products. Wade Scheel, director of safety, health and compliance for Stericycle, said in a statement that the company sees opportunities for the agency to fill gaps in regulation of aerosol disposal, electronics disposal and the management of certain nicotine products.

The EPA is also working on a rule specifically for pharmaceutical waste.

"Hopefully, the administration will continue with these efforts to continue to provide relief to this unique waste generator sector," Scheel said.

Syngenta Faces 7,000 Kansas Farmers in Dispute Over Modified Corn

Posted June 05, 2017, 11:00 A.M. ET

By Margaret Cronin Fisk and Jef Feeley

Farmers have to deal with threats to their crops from nature all the time. Thousands of Kansans argue, however, that Syngenta AG posed an even bigger threat by failing to prevent its genetically modified corn seed from contaminating U.S. crops, which led to a devastating rejection of imports by Chinese officials.

More than 7,000 Kansas farmers were going to trial June 5 to convince a jury the agricultural giant rushed the genetically engineered seed to market before getting import approval from China, which then stopped shipments saying the corn had been contaminated (Syngenta AG MIR 162 Corn Litigation, D. Kan., No.14-md-02591, 6/5/17).

That move, and the farmers' inability to regain a foothold in China once other countries filled the void, depressed corn prices for years, their suit claims. They are seeking $200 million in lost sales, plus punitive damages.

Syngenta, which denies any wrongdoing and says its genetically modified seed wasn't responsible for price drops, almost went to trial over similar claims in April. A federal court in Minnesota had to reschedule those proceedings after it failed to seat a jury. Several other trials are coming up, including class actions, as lawyers pursue suits on behalf of some 350,000 corn growers claiming as much as $13 billion in losses.

Full Circle

In a twist, the lawsuit spurred by the Chinese action comes as state-owned China National Chemical Corp. is finalizing its $43 billion acquisition of Basel, Switzerland-based Syngenta. A win for the farmers over Syngenta's sales of the seeds would circle back to the Chinese government that rejected the grain.

Judge John Lungstrum, of the U.S. District Court for the District of Kansas, who is overseeing the trial and most of the litigation, has certified eight statewide classes so far and had said he'll set another trial this year. Farmers in 14 additional states are awaiting class certification decisions by the Kansas judge.

Grain exporters Archer-Daniels-Midland Co. and Cargill Inc. have accused Syngenta in separate lawsuits of carelessly allowing its seed to taint U.S. corn, prompting the Chinese rejection. Those suits are pending in state court in Louisiana, with Cargill's headed for trial next year. Syngenta's counterclaims against both companies were dismissed in Kansas last year.

Claims by several individual farmers will be featured as representative of the class in the Kansas City trial. Those farmers are hardly huge agribusinesses, according to their complaint. One of the representatives, David Polifka, planted about 1,000 acres of corn in 2013 and again in 2014 in Gove County, in western Kansas. Another, Charles Frickey, planted about 180 acres of corn in 2012 and 140 acres in 2014 in Decatur County, in the northwestern part of the state.

Insect-Resistant

Syngenta began marketing its Viptera insect-resistant corn in 2011 following U.S. approval the prior year.

The farmers say that Syngenta was reckless both in allowing the trait to contaminate U.S. crops and selling a second GMO seed that also hadn't been approved by China. Syngenta misled the industry on the timing of an expected approval from China, the farmers allege, citing internal company documents and public statements.

In 2012, according to the farmers' complaint, then-chief executive officer Mike Mack told analysts on a conference call that Syngenta expected to have Chinese approval within "a couple of days." Mack did qualify that statement on the call, the company said in court papers, adding at the time that he couldn't "handicap definitively" when China would act.

China didn't approve the trait until 2014, and Syngenta knew that approval wasn't imminent in 2012, the farmers said.

Cratering corn prices cost massive losses to farmers and a chance at a growing market, according to the lawsuit. Even after China approved the seed, prices remained depressed because the country had found new sources for corn, they said.

Syngenta denies misleading the industry and has called the damages claims speculative.

The trials may rise or fall on those claims, said law professor Anthony Sabino, of St. John's University in New York. "It's not enough for these plaintiffs to prove liability," he said.

"For the farmer plaintiffs here, they have to present hard economic facts that prove their market losses," Sabino said. "More than one plaintiff has done a bang-up job of proving liability only to fall flat on proving damages."

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No New Data Needed for Nanomaterials Rule, EPA Official Says

Posted June 05, 2017, 6:01 A.M. ET

By Pat Rizzuto

Companies making and processing nanoengineered chemicals do not have to generate new information to comply with the agency's data collection rule that is effective in August, an EPA manager said.

The rule is the first any federal agency has issued addressing any intentionally engineered nanoscale chemical. BASF SE and the Dow Chemical Co. are among the many chemical manufacturers making nanoengineered chemicals for markets as diverse as aeronautics, electronics, transportation, and sports equipment. "Only report what's in your possession. You don't have to develop surveys or information," Jim Alwood, a manager in the Environmental Protection Agency's new chemicals program, said during a June 1 webinar organized by Semiconductor Equipment and Materials International (SEMI).

The goal of the rule is to get information on chemicals in commerce, Alwood told the global trade association that represents the semiconductor and flat panel display equipment and materials industries. "To manage risks, we need to know which nanoscale materials are in commerce."

"You are just required to submit the information you have. It goes back to what's in commerce and what you know about it," he said. Processors, for example, may not have many specific details about the nanoscale chemical they purchase, but they can tell the agency what they do with it, Alwood said.

Processors mix or otherwise work with a chemical without causing it to transform into other compounds.

Alwood answered questions received during the webinar and questions he said he has heard repeatedly before and after EPA's final rule (RIN: 2070-AJ54) was published in January (82 Fed. Reg. 3641). The agency has delayed the rule's effective date until Aug. 14 (82 Fed. Reg. 22,088).

He encouraged companies to submit more questions by June 15. The agency plans to answer such questions in guidance it announced May 16 (82 Fed. Reg. 22,452).

The rule applies to existing chemicals intentionally designed at the nanoscale—one to 100 nanometers—to have special strength, electrical or other properties they would not have if made in larger dimensions. A human hair is approximately 80,000-100,000 nanometers wide.

Rule's Goals

The rule's goals, Alwood said, are to ensure the EPA knows which nanoengineered chemicals are in commerce and to help the agency decide whether some of those chemicals or some ways companies work with them could pose a risk to workers, the general public or the environment. That information would help the agency decide whether it needs yet more information or if some type of risk management were needed, he said.

Any requests for additional data or regulatory actions would be pursued separately under the normal regulatory notice and comment or other procedures authorized by the Toxic Substances Control Act amendments of 2016, Alwood said.

R&D Generally Exempted

Alwood said he also is hearing many questions about how the rule affects research and development (R&D).

Research involving nanoengineered chemicals is generally exempt from the rule, Alwood said. Companies or other institutions that "manufacture or process, or intend to manufacture or process these chemical substances as part of articles, as impurities, or in small quantities solely for research and development" are exempt, the final rule said.

Michael Castorano of Dow Electronic Materials asked how much a company would have to change a specific nanoengineered chemical before it became a new form of the chemical that the company would have to report.

"You aren't going to need to report every change," Alwood said. The agency wants new information if a company is redesigning a chemical to give it a different size or shape to enable it to function differently than it did, he said.

Eventually, EPA's guidance will be on its website and periodically updated, he said.

N.C. Farm, Owner Fined For Discharging Cow Waste

Posted June 05, 2017, 03:59 P.M. ET

By Andrew M. Ballard

A North Carolina farm and its owner have been sentenced on criminal charges for violating the Clean Water Act by discharging animal waste into a tributary of the French Broad River without a permit.

Asheville, N.C.-based Crowell Farms Inc. and its owner, Michael Alexander Crowell, were fined $40,000 and $10,000, respectively, and given a three-year probationary term by the U.S. District Court for the Western District of North Carolina June 1. Crowell must serve six months of his probationary term under house arrest, and the farm is required to abide by an environmental

compliance program for those three years as well (United States v. Crowell Farms Inc., W.D.N.C., No. 1:16-cr-00113, sentencing 6/1/17).
Crowell and his company both pleaded guilty in November 2016 to a single count of violating the Clean Water Act by discharging pollutants without a permit. The defendants' attorney told Bloomberg BNA June 5 that the farm's owner regretted his "poor judgment" and has taken steps to prevent future violations at the cattle farm.
According to federal prosecutors, for at least a few weeks in late 2015, Crowell installed bypasses at the farm's waste lagoons because he was having difficulty with managing the ponds' levels due to rainfall. Crowell's farm, which housed more than 150 cows, only was permitted to discharge liquid waste to an on-site land application system and not directly into bodies of water.
Through the bypass, Crowell illegally discharged the liquid animal waste into a tributary of the French Broad River, which is used as a drinking water source and for recreational purposes and fishing.
"Michael regrets his poor judgment, and since the date of the offense has been working with environmental regulators to make sure nothing like this happens again," according to Stephen L. Cash, an attorney with the Asheville-based law firm of Cloninger, Barbour, Searson, Jones & Cash who represented the farm and Crowell.
Cash said in an email to Bloomberg BNA that Crowell has never before been convicted of a crime and "is glad to be able to put this matter behind him and glad that he has caused no lasting damage to the French Broad watershed."

Trump's Paris Exit Sidelines D.C. for Danes Blazing Wind Trail

Posted June 05, 2017, 11:21 A.M. ET

By Peter Levring

For Denmark, which relies more on wind energy than any other nation on the planet, June 1 was a pretty bad day.
The country's energy minister, Lars Chr. Lilleholt, watched in dismay as U.S. President Donald Trump extracted the world's biggest economy from the Paris accord, ignoring decades of science-based work that had guided political efforts to protect the globe from climate change.
But Lilleholt says the move also ignored the sound economics of renewable energy, and if the White House isn't listening, he's ready to take his message elsewhere.
The minister's next stop is China, where he'll discuss green energy this week at an event with about 20 other nations (representatives from the U.S. will also be there). Lilleholt says the view in Washington D.C. can't upend a movement that China, India and Europe all support. What's more, he expects American states to ignore Trump's agenda and continue using green energy. He says he's already received signals from local governments to that effect.
"It's my expectation that a number of U.S. states, east-coast states and Texas, among others, will continue to back this," Lilleholt said in an interview in Copenhagen. "Regardless what Trump says, the green transition will continue across the world, and in the U.S."
According to what the Danish government is hearing, Trump is likely to be isolated in his decision to abandon the Paris accord.
The pact still "looks solid," Lilleholt said. "The rest of the world stands together. The EU is united, we've heard from China, India, the U.K. I haven't heard of any other nations preparing to exit."
Lilleholt's travel itinerary sheds some light on the global leadership shift in an area that's proving more economically viable than fossil fuel production. Or, as Columbia University Professor Jeffrey Sachs puts it, Trump's decision to exit the Paris climate accord "is handing industrial leadership outside the U.S."
Denmark, which is home to Vestas Wind Systems A/S, the world's biggest wind-turbine maker, and Dong Energy A/S, the world's biggest offshore wind-park operator, has long played a prominent role in global renewable energy policies.
Vestas estimates that the U.S. wind industry "supports more than 100,000 jobs in 50 states, and it brings billions of dollars in economic development to the communities that host the projects," said Morten Dyrholm, a senior vice president for marketing at the company.
Denmark, which already gets about 40 percent of its electricity from wind power, is on target to have all its energy needs covered by renewables by 2050. Much of the new capacity will be built without subsidies. Lilleholt says Denmark's experience makes clear that coal is no longer cheaper to produce than renewable energy.

Lilleholt says Denmark will lobby hard in the European Union for the bloc to take a bigger role in the Paris accord now that the U.S. is out of the arrangement. He also said it was too much to expect the rest of the world to absorb the gap left by the U.S.
"We can't just distribute the U.S. obligations on 15 percent of the emissions to the other countries," he said.
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How Hard Will Pruitt Crack Down on Lake Erie Farmers?

Posted June 05, 2017, 7:01 A.M. ET

By David Schultz

The business of growing food in the upper Midwest may be about to significantly change.
An agreement reached last year between the U.S. and Canada may force state and federal officials to impose new limits on the amount of fertilizer that can be applied by farmers in parts of Ohio, Indiana, and Michigan. The two countries are seeking to halve the amount of nutrients, mostly from farms, that wash into Lake Erie. High levels of nutrients can cause algae blooms that contaminate the lake, an important drinking water source.
Some Lake Erie farmers have voluntarily adopted measures to reduce their fertilizer use and prevent the erosion of their topsoil. But, depending on how the binational process plays out, adopting those types of soil conservation measures may no longer become voluntary, something that deeply worries the local agriculture industry.
"Farmers are not big fans of regulation," Joe Cornely, a spokesman with the Ohio Farm Bureau, told Bloomberg BNA. "Decisions are best made locally."

Good Soil's Not Pretty

So what does it look like when a farmer adopts these soil conservation measures? In northwest Ohio, in early spring, one of these fields is not very pretty.
It's cold and wet, and the snowmelt has saturated the soil creating a dark black mud. A week or two before planting season, no one is working in the fields. Instead dead plants—an assortment of partially decomposed radishes, peas, oats and sunflowers—litter the untilled rows.
This farm belongs to Mike Libben, head of the local Soil and Water Conservation District in Ottawa County just outside of Toledo. Libben's farm may not be aesthetically pleasing, but everything he does is geared toward enriching his soil with nutrients and preventing it from washing away.
He's installed more efficient drainage systems that allow him to store water under his fields. He doesn't till his land, because that promotes erosion. And he plants cover crops—the radishes, peas, oats and sunflowers—which hold the soil in place and infuse it with nutrients after they decompose, reducing the need for more fertilizer.
An evangelist for this type of farming, Libben tries to persuade his neighbors through the conservation district to take similar measures. The goal is to reduce the amount of nutrient-laden sediment washing off into Lake Erie, the main source of drinking water for dozens of cities and towns, including Toledo.
Some farmers are receptive, he said, but others are stubbornly immune to his pitches. "It still always comes back to the cost," he told Bloomberg BNA. "'What's the bottom line for me? You want me to spend how many dollars and I don't get anything for it?' But it's the hidden benefits of it."

No Longer Voluntary?

The benefits of soil conservation become more clear when considering what happens when too much fertilizer washes off of farms and drains into Lake Erie. The fertilizer contains nutrients, primarily phosphorus, that are the primary cause of massive algae blooms that have plagued the western part of the lake in recent years.
A large algae bloom can suck all of the oxygen out of the water, creating hypoxic dead-zones where aquatic life can't survive.
And, under certain circumstances, these blooms can release toxins that are hard to detect in drinking water. In the summer of 2014, more than 400,000 residents in and around Toledo were told not to use their taps for three days after the city's water utility was surprised by an algae bloom that formed right in front of its intake pump inside Lake Erie.
Partly spurred on by this incident, the U.S. reached its agreement with Canada last year to reduce the amount of nutrients trickling into Lake Erie by 40 percent.
As a part of the Lake Erie agreement with Canada, which was signed less than a year before the end of the Obama administration, each country has to develop a set of actions to meet the 40 percent nutrient reduction target by February 2018.

Farm Runoff

While nutrients can come from many sources, such as sewers that carry human waste as well as phosphorus-rich detergents away from homes and businesses, farms contribute the overwhelming majority that winds up in Lake Erie and other bodies of water. More than 65 percent of the phosphorus in Lake Erie comes from farms, according to the Ohio Sea Grant. And in northwest Ohio, farmland dominates the landscape. Nearly three quarters of the land that drains into the Maumee River, the largest western tributary into Lake Erie, is used for agriculture, according to the National Center for Water Quality Research.

But if this region has been farmed for generations, why are algae blooms suddenly a problem now? Climate change is one unavoidable reason, Gail Hesse, head of the National Wildlife Federation's Great Lakes program, said.

Lake Erie is the shallowest of the Great Lakes, and the lake is at its shallowest in its western third near Toledo. That means that rising air temperatures can more easily warm the water there, creating optimal conditions for algae growth. Additionally, even though farmers have become more efficient in applying fertilizer over the years, storms have also become more intense, washing more topsoil into the lakes.

Hesse said the Trump administration won't be able to avoid these facts when crafting its plan to get to 40 percent. "There's no way to achieve those targets without putting restrictions on agriculture in the western basin," she told Bloomberg BNA.

Agreement Moving Forward

At first glance, it would seem as if the Environmental Protection Agency, which is responsible for crafting the U.S. action plan, would have little appetite to take measures that dictate to farmers when and how they can apply fertilizer.

The new administration has consistently staked out pro-business positions on nearly every environmental issue and the agency's new leader, Scott Pruitt, was lauded with three standing ovations when he spoke at a Farm Bureau conference shortly after taking office.

But, so far, there's no evidence that the EPA is abandoning the Lake Erie agreement.

Wendy Carney, a deputy director in the EPA's Great Lakes regional office, said the agency is collaborating with the five states in the Lake Erie watershed on to come up with an action plan. She said they're on track to release a draft version this summer and then finalize it before the end of this year, several months ahead of schedule.

"Agricultural runoff is the top priority for management efforts, particularly in the Maumee River basin," Carney told Bloomberg BNA in an email.

Sandra George, one of Carney's counterparts across the border, also said the change in administrations in the U.S. has had no effect on the two countries' work.

"We still meet," George, a program coordinator in Canada's federal environmental agency, told Bloomberg BNA. "We're doing what we need to do."

'Fans of Regulation'

Cornely, the Ohio Farm Bureau spokesman, said he hopes the EPA takes into account all of the action on this issue that's been happening at the state and local levels. As an example, he pointed to the law Ohio Gov. John Kasich (R) signed in 2015 banning the application of fertilizer on frozen or saturated ground, when it's more susceptible to washing away.

Conditions across the Lake Erie watershed, from Toledo in the west to Buffalo in the east, vary so much that a top-down solution to the runoff problem is not feasible, he said.

"If the overall goal is for each of these government subdivisions to reach [a target], it seems to me to let each one of those entities figure out how to get there," Cornely said. "It's pretty rare that a one-size-fits-all regulation works."

But Cornely acknowledged that, if farmers want the EPA to go gentle on them in regulating runoff, they will need to show that they can deal with the problem themselves. This probably will involve more enthusiastic adoption of the kinds of soil conservation measures that Libben is trying to get his neighbors to adopt, he said.

"If you ask for the authority to stay local, it's incumbent upon you to come up with something that works," Cornely said. "Rights come accompanied by responsibility." This story was made possible in part by a fellowship with the Institute for Journalism & Natural Resources.

E-Commerce Boosts Demand for Brownfields Redevelopment

Posted June 05, 2017, 6:31 A.M. ET

By Sylvia Carignan

The e-commerce industry's appetite for warehouse space near major cities is boosting demand for brownfields as well as environmental insurance.

The trend is especially strong in New Jersey, where more than 50 percent of brownfields redevelopment projects are leased for online retail uses, according to commercial real estate firm Jones Lang LaSalle Inc. Other companies investing in brownfields for e-commerce include FedEx Corp., Under Armour Inc., and Wal-Mart Stores Inc.

With the increased demand for brownfields—which are often former industrial or commercial sites with environmental contamination—sites get cleaned up more quickly and can promote local economic growth.

"The demand has never been as high as it's been today," said Robert Kossar, who manages New Jersey operations for Jones Lang LaSalle Inc.

The same is true in other major metropolitan areas, according to Dan French, who is the chief executive officer of Brownfields Listings, which runs an online bulletin board for brownfields sites open for redevelopment and developers looking for sites.

He told Bloomberg BNA the current demand for warehouse space is "historic." "Land availability is getting tight in well developed locations, like say the I-55 corridor here in Chicagoland, but the demand for space just keeps growing," French said, referring to the Chicago metropolitan area. "The consumer isn't slowing down and neither is e-commerce growth, so the buildup will go on."

Growing Insurance Demand

The demand for environmental insurance also has grown in the first half of 2017, said Glynis Priester, national practice leader in the environmental sector at Wells Fargo.

"On the growth front it is kind of a buyer's market, which I think is helping to drive new customers to buying environmental insurance," Priester told Bloomberg BNA. But there is strong interest in New Jersey from clients who are developing brownfields sites into warehouse space and need insurance coverage for environmental liabilities, Priester said.

"We are seeing a lot of developers who, in the past, really didn't have an appetite to acquire properties that were distressed, or saw a lot of contamination," she said. The high demand for real estate has turned that perspective around, despite the increased price of redeveloping a brownfield.

"Because there is such a dearth of available land, and because of the expense of that land, brownfield redevelopment has been the only means of redevelopment for this entire cycle," Kossar told Bloomberg BNA.

Ultimately, French said, brownfields benefit.

"The long-term trends are in place, industrial rents are [higher]," he said, "and it's great news for brownfield sites."

Investing in Brownfields

FedEx and Under Armour have signed leases to build distribution centers at the former Bethlehem Steel mill complex outside Baltimore.

Testing at the former steel mill showed the presence of lead, semi-volatile organic compounds, and polychlorinated biphenyls, among other contaminants. Cleanup efforts are proceeding under Maryland's voluntary cleanup program.

Offshore contamination near the site is being remediated under the Comprehensive Environmental Response, Compensation, and Liability Act, according to Maryland state documents.

According to Jones Lang LaSalle, the incentives for building at that site include a 10-year property tax credit, employment and job tax credits for being in the Chesapeake Enterprise Zone, and incentives from the regional power company.

FedEx chose the brownfield site "primarily because of its ease of access to major highways, proximity to customers' distribution centers and a strong local community workforce for recruiting employees," Meredith Heighington Miller, a spokeswoman for the company, said.

Under Armour referred Bloomberg BNA questions about the site to the developer.

French pushes brownfield owners in less popular markets to make their sites more appealing by preparing their sites for developers to start their work as soon as possible.

"If significant environmental issues need to be resolved, or a brownfield is early in the redevelopment process and not much information is known, then it can take longer than [developers] can afford to wait," he said.

China Is Said to Halt New Electric-Car Production Permits

Posted June 05, 2017, 11:25 A.M. ET

By Bloomberg News

China plans to halt issuing permits to produce electric vehicles pending a review of the policy because of concern additional approvals may lead to a glut in the world's biggest auto market, according to people familiar with the matter.

The National Development and Reform Commission, which oversees new investments in the auto industry, wants to evaluate the program after handing out 15 production licenses since March 2016, said the people, who asked not to be identified because the discussions aren't public. The NDRC didn't immediately respond to a faxed request for comment.

China has identified new-energy vehicles as a strategic emerging industry and aims to boost annual sales of plug-in hybrids and fully electric cars by 10-fold in the next decade. Besides giving generous subsidies for both consumers and manufacturers, the government created a class of permits allowing companies including billionaire Lu Guanqiu's Wanxiang Group and a Volkswagen AG joint venture to produce only electric vehicles, while imposing a moratorium on new capacity for the manufacture of conventional gasoline-run vehicles.

The state support helped China surpass the U.S. in 2015 to become the world's biggest market for new-energy vehicles—comprising electric vehicles, plug-in hybrids and fuel-cell cars. A total of 507,000 such vehicles were sold last year in the country, according to the China Association of Automobile Manufacturers.

While a suspension of new permits may delay plans by companies such as Internet entrepreneur William Li's NIO and Jia Yueting-backed LeEco's electric-car unit that have said they intend to apply, it may help incumbent electric-car manufacturers including BYD Co. and BAIC Motor Corp. by limiting the number of new entrants to the industry. Volkswagen's joint venture with Anhui Jianghuai Automobile Group Corp. received the 15th license to produce EVs.

To date, newly set up companies in China have announced at least 98 billion yuan ($14 billion) of investments to build electric car factories with a total annual capacity of 2.9 million units a year, or six times the number of plug-ins sold last year, according to data compiled by Bloomberg from company statements.

Apart from Karma Automotive owner Wanxiang Group, other companies that received the permits to manufacture electric vehicles include auto-parts maker Minth Group, car designer Beijing CH-Auto Technology Co., Beijing Electric Vehicle Co., Hangzhou Changjiang Passenger Vehicle Co. and a unit of Chery Automobile Co.

Chinese Premier Li Keqiang said last week the country will stick to its pledges to tackle global warming. President Donald Trump said he would withdraw the U.S. from the Paris climate pact because it favored other nations, a move seen as an opening for China to burnish its image as a global leader on environment issues.

—With assistance from Yan Zhang.

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Message

From: Branning, Amy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=A3F510CCED11492D88CC26ED073B7F10-ABRANNIN]
Sent: 5/30/2017 5:18:39 PM
To: Simons, Andrew [Simons.Andrew@epa.gov]
CC: Talty, Mark [Talty.Mark@epa.gov]; Thompson, Lisa [Thompson.Lisa@epa.gov]
Subject: RE: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Hi Mark:

Thank you for offering to set up the call. Mine should work.

Some of my ARLO colleagues seem to have issues with the participant code. I have not had that problem. But if there is a problem, try Ex. 6 Personal Privacy (PP) Thank you and talk to you shortly.

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

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-----Original Message-----
From: Branning, Amy
Sent: Tuesday, May 30, 2017 1:12 PM
To: Simons, Andrew <Simons.Andrew@epa.gov>
Cc: Talty, Mark <Talty.Mark@epa.gov>; Thompson, Lisa <Thompson.Lisa@epa.gov>
Subject: RE: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Hi Andy:

1:30 pm is good. Below is the call in number. I will also send out an invite. Thank you so much.

Ex. 6 Personal Privacy (PP)
Your Seven Digit Conference Extension is: Ex. 6 Personal Privacy (PP)
Your Participant Code is: Ex. 6 Personal Privacy (PP)

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

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-----Original Message-----
From: Simons, Andrew
Sent: Tuesday, May 30, 2017 1:10 PM
To: Branning, Amy <Branning.Amy@epa.gov>
Cc: Talty, Mark <Talty.Mark@epa.gov>
Subject: RE: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Both Mark and I are available at 1:30, if that time works for you. Not so easy for me to set up a conference line at the moment, so if that's possible that would be great. Alternatively, am reachable at my work number (rolls over to my work cell).

Andrew Simons
Assistant General Counsel for Regulatory Issues Office of General Counsel (MC 2322A) U.S. Environmental Protection Agency

1200 Pennsylvania Ave, NW Washington, DC 20460 Phone (202) 564-3649

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From: Branning, Amy
Sent: Tuesday, May 30, 2017 12:58 PM
To: Simons, Andrew
Cc: Talty, Mark
Subject: RE: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Hi Andy:

I forgot to mention that you can just dial my work number (564-1744) and it will transfer to my flexiplace number.

Also, If it is easier for you to just call me directly when you have a free moment, please go ahead. If I can't answer your questions, I will follow up with my program contact.

I also forgot to thank you for your prompt response and sorry to bother you while you are out.

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

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-----Original Message-----
From: Simons, Andrew
Sent: Tuesday, May 30, 2017 11:52 AM
To: Branning, Amy <Branning.Amy@epa.gov>; Talty, Mark <Talty.Mark@epa.gov>
Cc: Zenick, Elliott <Zenick.Elliott@epa.gov>
Subject: RE: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Amy:
I am unexpectedly out of the office and am trying to plug in when I can. I have a few questions, and I think it would be more efficient if we talked. I'm going to try and participate in a 12 PM conference call but could call you later today. Is there a good time to reach you?
Andy

Andrew Simons
Assistant General Counsel for Regulatory Issues Office of General Counsel (MC 2322A) U.S. Environmental Protection Agency
1200 Pennsylvania Ave, NW Washington, DC 20460 Phone (202) 564-3649

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From: Branning, Amy
Sent: Tuesday, May 30, 2017 10:42 AM
To: Simons, Andrew; Talty, Mark
Cc: Zenick, Elliott
Subject: FW: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Hi Andy:

Ex. 5 AC/AWP/DP

Ex. 5 AC/AWP/DP

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

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From: Thompson, Lisa
Sent: Tuesday, May 30, 2017 10:10 AM
To: Branning, Amy <Branning.Amy@epa.gov>
Subject: FW: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Amy – here are the OMB comments on the propsed stay – I don't think Ex. 5 Attorney Client (AC)
Ex. 5 Attorney Client (AC)

From: Cozzie, David
Sent: Friday, May 26, 2017 1:18 PM
To: Thompson, Lisa <Thompson.Lisa@epa.gov<mailto:Thompson.Lisa@epa.gov>>
Subject: FW: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Peter has sent to Erica to send to Darryl and AEG

From: Szabo, Aaron L. EOP/OMB [mailto:Aaron_L_Szabo@omb.eop.gov]
Sent: Thursday, May 25, 2017 8:43 PM
To: Cozzie, David <Cozzie.David@epa.gov<mailto:Cozzie.David@epa.gov>>; Tsirigotis, Peter <Tsirigotis.Peter@epa.gov<mailto:Tsirigotis.Peter@epa.gov>>
Cc: Szabo, Aaron L. EOP/OMB <Aaron_L_Szabo@omb.eop.gov<mailto:Aaron_L_Szabo@omb.eop.gov>>; DeBruhl, Brandon F. EOP/OMB <Brandon_F_DeBruhl@omb.eop.gov<mailto:Brandon_F_DeBruhl@omb.eop.gov>>
Subject: Summary of Interagency Comments under EO12866 and 13563 for EPA Proposed Rule -- Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements (RIN 2060-AT59)

Attached please find the summary of interagency comments under EO 12866 and 13563 for the EPA draft proposed rule entitled, "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements" (RIN 2060-AT59).

Please let me know if you have any questions.

Aaron L. Szabo
Policy Analyst
Office of Information and Regulatory Affairs Office of Management and Budget
202 Ex. 6 Personal Privacy (PP)
Aaron_L_Szabo@omb.eop.gov<https://eopowa.whca.mil/owa/redir.aspx?C=G5jxRA7u3s_EW-PzDMmGEMYUVTQu1S_cgt8jLnsowd0fDQSbSMzTCA..&URL=mailto%3aAaron_L_Szabo%40omb.eop.gov>

Message

From: Branning, Amy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=A3F510CCED11492D88CC26ED073B7F10-ABRANNIN]
Sent: 6/7/2017 1:05:34 PM
To: Jordan, Scott [Jordan.Scott@epa.gov]; Mills, Derek [Mills.Derek@epa.gov]
CC: Bangser, Paul [bangser.paul@epa.gov]; Zenick, Elliott [Zenick.Elliott@epa.gov]
Subject: RE: Methane rule

Ex. 5 Deliberative Process (DP)

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

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From: Jordan, Scott
Sent: Wednesday, June 07, 2017 9:04 AM
To: Branning, Amy <Branning.Amy@epa.gov>; Mills, Derek <Mills.Derek@epa.gov>
Cc: Bangser, Paul <bangser.paul@epa.gov>; Zenick, Elliott <Zenick.Elliott@epa.gov>
Subject: Re: Methane rule

Amy and Derek -

Ex. 5 Deliberative Process (DP) / ACP

Scott Jordan
Air and Radiation Law Office
Office of General Counsel
202-564-7508

From: Bangser, Paul
Sent: Wednesday, June 7, 2017 8:50 AM
To: Jordan, Scott
Subject: Methane rule

Hi Scott,

Ex. 5 Deliberative Process (DP) / ACP

Paul Bangser
Attorney, Office of General Counsel

U.S. Environmental Protection Agency
202-564-5479
bangser.paul@epa.gov

From: Bloomberg BNA [mailto:bloomberg@bna.com]
Sent: Monday, June 05, 2017 4:15 PM
To: Bangser, Paul <bangser.paul@epa.gov>
Subject: June 5 -- Daily Environment Report - Afternoon Briefing

Bloomberg BNA

Daily Environment Report

Afternoon Briefing - Your Preview of Today's News

The following news provides a snapshot of what Bloomberg BNA is working on today. Read the full version of all the stories in the final issue, published each night. The Bloomberg BNA Daily Environment Report is brought to you by EPA Libraries. Please note, these materials may be copyrighted and should not be forwarded outside of the U.S. EPA. If you have any questions or no longer wish to receive these messages, please contact Josue Rivera-Olds at rivera-olds.josue@epa.gov, 202-566-1558.

EPA Taken to Court Over Methane Rule Pause
Posted June 05, 2017, 12:12 P.M. ET
By David Schultz
A coalition of environmental groups is taking the EPA to court over its decision to halt an Obama-era regulation on methane emissions from the oil and gas industry.
The groups, which include the Environmental Defense Fund, Natural Resources Defense Council, and Sierra Club, filed suit in a federal appeals court just days after the Environmental Protection Agency announced it would delay the regulation's upcoming compliance deadlines by at least three months while it weighs whether to repeal the regulation altogether. (The Sierra Club has received funding from Bloomberg Philanthropies, the charitable organization founded by Michael Bloomberg, founder of Bloomberg L.P. Bloomberg BNA is an affiliate of Bloomberg L.P.)
The regulation, enacted during the Obama administration, requires oil and gas drillers to step up their monitoring for leaking methane, a potent greenhouse gas. The plaintiffs in the lawsuit want the appeals court to overturn the EPA's delay of the regulation's upcoming deadlines. (Clean Air Council v. Pruitt, D.C. Cir., No. 17-01145, 6/5/17.)

EPA 'Safer Choice' Label Program, Criteria Under Fire
Posted June 05, 2017, 7:30 A.M. ET
By Pat Rizzuto
Does a detergent that Procter & Gamble Co. makes merit a 'safer' label designation? The issue has re-ignited a debate among trade association executives over the type of analysis needed to justify such labels.

Some sections of the chemical industry would like to see the Environmental Protection Agency adopt a risk-based approach that would consider additional factors when determining what products qualify for a Safer Choice label. However, other business voices and environmental advocates have voiced opposition to such a move, which one chemical industry specialist said could lead to endless debates over chemical risk estimates.

The debate over the EPA's approach to reviewing products occurs as continued funding for the Safer Choice program is uncertain: the White House's fiscal year 2018 budget request would zero out funding for those activities.

Three CEOs recently discussed the future of the Safer Choice program, a voluntary initiative through which companies can demonstrate that their products are made with chemicals that are safer or more environmentally-friendly than alternatives. Companies seek the Safer Choice label to show customers that there are eco-friendly, less toxic household products on the market.

"Chemicals in commerce should be assessed based on their risk and exposure," Cal Dooley, president and CEO of the American Chemistry Council said May 18 during the Consumer Specialty Products Association's mid-year meeting. "We will consistently oppose any assessment of chemicals that is based on a hazard-only approach," he said.

The CEO for another trade association and chemical policy specialists from environmental and labor groups argued that hazard-based approaches present clear criteria consumers can trust.

A hazard-based approach looks only at the properties of an ingredient, such as the ability of table salt to raise blood pressure. A risk-based approach also would consider the probability that the hazard would happen, taking into consideration factors such as level and frequency of exposure.

Dooley said P&G's Tide® Coldwater detergent is a "classic example" of the problems that arise with hazard-based chemical assessment. The detergent cleans clothes without the need for hot water thereby reducing consumers' energy bills, according to P&G.

Despite those environmental benefits, the detergent didn't qualify for the EPA's Safer Choice label because it had two ingredients that posed a greater hazard than are allowed under the program's criteria, Dooley said.

"How is a product like this that is going to reduce energy consumption, reduce greenhouse gas emissions, not a safer choice for the environment?," Dooley said.

Metrics

An EPA spokeswoman confirmed that agency staff spoke with P&G about its detergent in 2007, when the Safer Choice program was called Design for the Environment. The EPA spokeswoman said the company didn't formally apply for the label. All other aspects of the discussions are confidential, she said.

Tracey Long, a P&G spokeswoman, told Bloomberg BNA: "We appreciate programs like Safer Choice. We also see opportunities to incorporate a broader array of environmental metrics into Safer Choice that would make it even more informative," she said.

The voluntary Safer Choice program encourages products to achieve certain standards. Safer Choice and its criteria were developed by industry, consumer, environmental, and labor groups in partnership with the EPA to encourage use of chemicals that are the safest available for the function they perform in a product.

The standards updated in 2015, for example, encourage "the use of energy-saving technologies including the use of concentrates and detergents that work in cold water." The program also requires products that bear the Safer Choice label to meet certain "master criteria."

All chemical ingredients, regardless of their percentage in the product, are examined. Each ingredient must meet specific, measurable targets that attest to its lack of or reduced carcinogenicity, reproductive/developmental toxicity, toxicity to aquatic life, and persistence in the environment, EPA's website says.

Chemicals known or expected to cause cancer in people, for example, would not be allowed in a product carrying a Safer Choice label.

Adding Risk to the Equation

The Consumer Specialty Products Association supports the Safer Choice program, Steve Caldeira, president and CEO of that association, told Bloomberg BNA.

"Our member companies have made significant investments in the program which now has over 2,000 brands and 500 companies participating," he said following the mid-year meeting.

The program fosters innovation and competition among companies and benefits consumers but could benefit by adding more flexibility such as adding risk to its criteria, Caldeira said.

Risk-based chemical analyses, for example, could allow Safer Choice labeling to be based on a wider spectrum of chemicals' health and environmental effects than may be possible through the hazard-based toxicity and environmental effects criteria currently used, Caldeira said.

`Magic' With Numbers

Charlotte Brody, vice president of health initiatives for the BlueGreen Alliance, told Bloomberg BNA the program could start losing support from environmental and labor groups if it moved towards a risk-based approach.

"Hazard gives us a more science-based framework that is less likely to be gamed," Brody said. Using risk-based methods could mean "we would very quickly move away from good science and move to estimates of estimates of estimates," Brody said.

"We could spend 10 years arguing about how much of a dangerous chemical is too much," Brody said. "When we start arguing how much is too much we move away from good science and move to magic with numbers—that's what's important about safer choice—clear criteria."

Consumers' Trust

If industry groups were to convince the Trump administration to move away from the compromises industries and advocacy organizations reached as they crafted Safer Choice, Brody said advocacy groups would start telling consumers the program could no longer be trusted.

"I imagine that not only we at BlueGreen, but all the greens at the table would move away and advertise that we think [Safer Choice] would be meaningless," Brody said.

David Levine, co-founder and CEO of the American Sustainable Business Council, said the cleaning product, clothing, food and other manufacturing companies that have joined the council "pay attention to what consumers are looking for, and one of those things is clarity in the market place."

"Safer Choice has set guidelines that have earned trust of consumers," Levine said.

Reducing energy consumption as cold water detergents do, is great, he said. "Companies should be investing in that, and investing in safer chemistries."

However, Levine said, Safer Choice was set up as a chemicals assessment program, not a program to reduce climate risks.

Jennifer McPartland, a health scientist at the Environmental Defense Fund, said it's inappropriate to judge Safer Choice's success by arguing it should have accomplished a goal for which it was never designed.

P&G should be commended for being innovative and designing a cold water detergent that cuts energy use, McPartland said. "It would be even more impressive" if eventually they also can get the ingredients in that product to meet the Safer Choice criteria, she said.

Safer Choice on the Chopping Block

The President's fiscal 2018 budget request would eliminate the EPA's Safer Choice program, because it seeks no funding for the Office of Pollution Prevention and Toxics' pollution prevention work. Other voluntary programs, such as the agency's Energy Star initiative that recognizes appliances and other products that save energy, also are on the chopping block.

"Zeroing out pollution prevention would be a disaster for American businesses," Levine said. "Increasing numbers of businesses are taking responsibility to make their products more sustainable, and government serves an important role in setting standards and developing credible labels."

Notwithstanding his preference for a risk-based approach to chemical assessment, Caldeira, with the Consumer Specialty Products Association, said it would be a mistake to eliminate the Safer Choice program.

U.K. Doesn't Think Paris Climate Deal Needs to Be Renegotiated

Posted June 05, 2017, 11:22 A.M. ET

By Alex Morales

Prime Minister Theresa May's government doesn't think the Paris climate deal needs to be renegotiated, her spokeswoman said, pitching Britain behind the position held by France, Germany and Italy.

"We don't believe it needs to be renegotiated," government spokeswoman, Alison Donnelly, told reporters in London. "We signed up to it, we remain committed to it."

The comment adds more substance to the U.K. stance, after May last week was criticized by opposition parties and the media for not being firmer in her criticism of President Donald Trump's decision to pull the U.S. out of the agreement.

May's office said last week that she had expressed her "disappointment" to Trump, but stayed silent on his stated desire to renegotiate the deal. By contrast, Germany, France and Italy issued

a joint statement in which they said: "we firmly believe that the Paris Agreement cannot be renegotiated."
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Hunt for Trump's Climate Views Like `Chasing Rabbit,' Perry Says

Posted June 05, 2017, 10:42 A.M. ET

By Stephen Stapczynski

News Story

(Bloomberg) --

People shouldn't focus on whether U.S. President Donald Trump believes climate change is real, according to one of his own Cabinet members.

"Those of you that focus on that are chasing a rabbit down a hole," U.S. Energy Secretary Rick Perry said to reporters in Tokyo June 5. "Is the climate changing? Yes. Is man having an impact? Yes," Perry said ahead of attending Clean Energy and Mission Innovation ministerial meetings in Beijing June 6.

While Trump said the U.S. was pulling out of the Paris climate accord, the president never stated his personal view about whether climate change is man-made. Speculation on his beliefs about climate change is a deflection by opponents who ignore ongoing U.S. leadership and innovation to lower emissions, Perry said.

Trump said he would withdraw the U.S. from the Paris agreement because it favored other nations, a move seen as an opening for China to burnish its image as a global leader on the environment. Business leaders have warned pulling the U.S. from the deal could put the country at a disadvantage in the race to develop and deploy clean-energy technology.

Perry challenged China to compete with U.S. energy technology, insisting that America isn't backing away from its position as a leader in cleaning up the environment.

"I hope China will step in and attempt to take the mantle away" from the U.S., Perry told reporters June 5 in Tokyo. "It would be a good challenge for them."

Perry also visited the wrecked Fukushima Dai-Ichi nuclear plant north of Tokyo June 4 and pledged American support for cleaning up the reactors, which melted down in 2011. He is scheduled to be in Beijing June 6, where he will meet with the world's biggest polluter and other nations and discuss the benefits of nuclear power, liquefied natural gas and renewables.

"Those that would say, 'well you created this void where China is going to take over' —no, we're not stepping back and we haven't created a void," Perry said. "The United States is not backing down from its role as a leader in cleaning up the planet."

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Retail Industry Seeks EPA Answers on Hazardous Waste

Posted June 05, 2017, 7:00 A.M. ET

By Sylvia Carignan

The retail industry is still waiting for the EPA to address a fundamental question: When does a product become waste?

The current state of confusion over the issue adds to the cost of the delivery, processing and handling of hundreds of thousands of different kinds of consumer goods that could be hazardous waste, such as multivitamins, nail polish and light bulbs, industry representatives told Bloomberg BNA.

"If you prematurely call something a waste, then it makes it very difficult for the retail industry to operate the way it does," Noelle Wooten, counsel at Kilpatrick Townsend & Stockton LLP, told Bloomberg BNA. Wooten counsels on chemical, drug packaging, retail and waste management.

It's harder to tell which retail wastes may be regulated by the Resource Conservation and Recovery Act as compared to industrial waste, which seems more clear-cut, said Richard Sieg, regulatory counsel for Inmar, a reverse distributor.

The EPA has not responded to Bloomberg BNA's questions on this topic.

Defining Waste

When a product is returned to the store, recalled, or produced in excess, it may become waste if there is no foreseeable sustainable use. Depending on its contents, the product may also be characterized as hazardous waste and then have to meet stricter disposal requirements.

"There's a disproportionate burden on retailers, especially when you consider the effect on human health and the environment," he said in a D.C. Bar event in May, referring to potential risks of consumer products that could be considered hazardous waste.

Reverse distributors generally accept those products and mark them for disposal or connect with suppliers and vendors who determine where the products could be used. Wooten estimates that the majority of goods sent to reverse distributors find sustainable uses.
But, the burden of answering the waste question, and navigating differences in each state's hazardous waste programs, falls to reverse distributors and retailers.

Filling Gaps

The EPA made a formal request for hazardous waste information from the retail industry in 2014, asking how much waste it generates, how employees are trained in hazardous waste handling, and what their reverse logistical practices are.
The agency released a strategy in 2016 acknowledging some of the issues the retail industry may face when seeking to comply with the Resource Conservation and Recovery Act.
"EPA recognizes that, although there are areas within the program that work well, RCRA regulations may not always be the best fit for the retail sector," the document states.
The EPA also recognizes that hazardous waste determinations differ from small businesses to big box retailers and department stores such as Lowe's, Target, and Macy's.
According to the strategy, the EPA "intends to develop a policy that addresses the reverse distribution process for the retail sector as a whole."
Stericycle Environmental Solutions manages waste, including retail products. Wade Scheel, director of safety, health and compliance for Stericycle, said in a statement that the company sees opportunities for the agency to fill gaps in regulation of aerosol disposal, electronics disposal and the management of certain nicotine products.
The EPA is also working on a rule specifically for pharmaceutical waste.
"Hopefully, the administration will continue with these efforts to continue to provide relief to this unique waste generator sector," Scheel said.

Syngenta Faces 7,000 Kansas Farmers in Dispute Over Modified Corn

Posted June 05, 2017, 11:00 A.M. ET

By Margaret Cronin Fisk and Jef Feeley

Farmers have to deal with threats to their crops from nature all the time. Thousands of Kansans argue, however, that Syngenta AG posed an even bigger threat by failing to prevent its genetically modified corn seed from contaminating U.S. crops, which led to a devastating rejection of imports by Chinese officials.
More than 7,000 Kansas farmers were going to trial June 5 to convince a jury the agricultural giant rushed the genetically engineered seed to market before getting import approval from China, which then stopped shipments saying the corn had been contaminated (Syngenta AG MIR 162 Corn Litigation, D. Kan., No.14-md-02591, 6/5/17).
That move, and the farmers' inability to regain a foothold in China once other countries filled the void, depressed corn prices for years, their suit claims. They are seeking $200 million in lost sales, plus punitive damages.
Syngenta, which denies any wrongdoing and says its genetically modified seed wasn't responsible for price drops, almost went to trial over similar claims in April. A federal court in Minnesota had to reschedule those proceedings after it failed to seat a jury. Several other trials are coming up, including class actions, as lawyers pursue suits on behalf of some 350,000 corn growers claiming as much as $13 billion in losses.

Full Circle

In a twist, the lawsuit spurred by the Chinese action comes as state-owned China National Chemical Corp. is finalizing its $43 billion acquisition of Basel, Switzerland-based Syngenta. A win for the farmers over Syngenta's sales of the seeds would circle back to the Chinese government that rejected the grain.
Judge John Lungstrum, of the U.S. District Court for the District of Kansas, who is overseeing the trial and most of the litigation, has certified eight statewide classes so far and had said he'll set another trial this year. Farmers in 14 additional states are awaiting class certification decisions by the Kansas judge.
Grain exporters Archer-Daniels-Midland Co. and Cargill Inc. have accused Syngenta in separate lawsuits of carelessly allowing its seed to taint U.S. corn, prompting the Chinese rejection. Those suits are pending in state court in Louisiana, with Cargill's headed for trial next year. Syngenta's counterclaims against both companies were dismissed in Kansas last year.
Claims by several individual farmers will be featured as representative of the class in the Kansas City trial. Those farmers are hardly huge agribusinesses, according to their complaint. One of the representatives, David Polifka, planted about 1,000 acres of corn in 2013 and again in 2014

in Gove County, in western Kansas. Another, Charles Frickey, planted about 180 acres of corn in 2012 and 140 acres in 2014 in Decatur County, in the northwestern part of the state.

Insect-Resistant

Syngenta began marketing its Viptera insect-resistant corn in 2011 following U.S. approval the prior year.

The farmers say that Syngenta was reckless both in allowing the trait to contaminate U.S. crops and selling a second GMO seed that also hadn't been approved by China. Syngenta misled the industry on the timing of an expected approval from China, the farmers allege, citing internal company documents and public statements.

In 2012, according to the farmers' complaint, then-chief executive officer Mike Mack told analysts on a conference call that Syngenta expected to have Chinese approval within "a couple of days." Mack did qualify that statement on the call, the company said in court papers, adding at the time that he couldn't "handicap definitively" when China would act.

China didn't approve the trait until 2014, and Syngenta knew that approval wasn't imminent in 2012, the farmers said.

Cratering corn prices cost massive losses to farmers and a chance at a growing market, according to the lawsuit. Even after China approved the seed, prices remained depressed because the country had found new sources for corn, they said.

Syngenta denies misleading the industry and has called the damages claims speculative.

The trials may rise or fall on those claims, said law professor Anthony Sabino, of St. John's University in New York. "It's not enough for these plaintiffs to prove liability," he said.

"For the farmer plaintiffs here, they have to present hard economic facts that prove their market losses," Sabino said. "More than one plaintiff has done a bang-up job of proving liability only to fall flat on proving damages."

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No New Data Needed for Nanomaterials Rule, EPA Official Says

Posted June 05, 2017, 6:01 A.M. ET

By Pat Rizzuto

Companies making and processing nanoengineered chemicals do not have to generate new information to comply with the agency's data collection rule that is effective in August, an EPA manager said.

The rule is the first any federal agency has issued addressing any intentionally engineered nanoscale chemical. BASF SE and the Dow Chemical Co. are among the many chemical manufacturers making nanoengineered chemicals for markets as diverse as aeronautics, electronics, transportation, and sports equipment. "Only report what's in your possession. You don't have to develop surveys or information," Jim Alwood, a manager in the Environmental Protection Agency's new chemicals program, said during a June 1 webinar organized by Semiconductor Equipment and Materials International (SEMI).

The goal of the rule is to get information on chemicals in commerce, Alwood told the global trade association that represents the semiconductor and flat panel display equipment and materials industries. "To manage risks, we need to know which nanoscale materials are in commerce."

"You are just required to submit the information you have. It goes back to what's in commerce and what you know about it," he said. Processors, for example, may not have many specific details about the nanoscale chemical they purchase, but they can tell the agency what they do with it, Alwood said.

Processors mix or otherwise work with a chemical without causing it to transform into other compounds.

Alwood answered questions received during the webinar and questions he said he has heard repeatedly before and after EPA's final rule (RIN: 2070-AJ54) was published in January (82 Fed. Reg. 3641). The agency has delayed the rule's effective date until Aug. 14 (82 Fed. Reg. 22,088).

He encouraged companies to submit more questions by June 15. The agency plans to answer such questions in guidance it announced May 16 (82 Fed. Reg. 22,452).

The rule applies to existing chemicals intentionally designed at the nanoscale—one to 100 nanometers—to have special strength, electrical or other properties they would not have if made in larger dimensions. A human hair is approximately 80,000-100,000 nanometers wide.

Rule's Goals

The rule's goals, Alwood said, are to ensure the EPA knows which nanoengineered chemicals are in commerce and to help the agency decide whether some of those chemicals or some ways

companies work with them could pose a risk to workers, the general public or the environment. That information would help the agency decide whether it needs yet more information or if some type of risk management were needed, he said.
Any requests for additional data or regulatory actions would be pursued separately under the normal regulatory notice and comment or other procedures authorized by the Toxic Substances Control Act amendments of 2016, Alwood said.

R&D Generally Exempted

Alwood said he also is hearing many questions about how the rule affects research and development (R&D).
Research involving nanoengineered chemicals is generally exempt from the rule, Alwood said. Companies or other institutions that "manufacture or process, or intend to manufacture or process these chemical substances as part of articles, as impurities, or in small quantities solely for research and development" are exempt, the final rule said.
Michael Castorano of Dow Electronic Materials asked how much a company would have to change a specific nanoengineered chemical before it became a new form of the chemical that the company would have to report.
"You aren't going to need to report every change," Alwood said. The agency wants new information if a company is redesigning a chemical to give it a different size or shape to enable it to function differently than it did, he said.
Eventually, EPA's guidance will be on its website and periodically updated, he said.

N.C. Farm, Owner Fined For Discharging Cow Waste

Posted June 05, 2017, 03:59 P.M. ET
By Andrew M. Ballard

A North Carolina farm and its owner have been sentenced on criminal charges for violating the Clean Water Act by discharging animal waste into a tributary of the French Broad River without a permit.
Asheville, N.C.-based Crowell Farms Inc. and its owner, Michael Alexander Crowell, were fined $40,000 and $10,000, respectively, and given a three-year probationary term by the U.S. District Court for the Western District of North Carolina June 1. Crowell must serve six months of his probationary term under house arrest, and the farm is required to abide by an environmental compliance program for those three years as well (United States v. Crowell Farms Inc., W.D.N.C., No. 1:16-cr-00113, sentencing 6/1/17).
Crowell and his company both pleaded guilty in November 2016 to a single count of violating the Clean Water Act by discharging pollutants without a permit. The defendants' attorney told Bloomberg BNA June 5 that the farm's owner regretted his "poor judgment" and has taken steps to prevent future violations at the cattle farm.
According to federal prosecutors, for at least a few weeks in late 2015, Crowell installed bypasses at the farm's waste lagoons because he was having difficulty with managing the ponds' levels due to rainfall. Crowell's farm, which housed more than 150 cows, only was permitted to discharge liquid waste to an on-site land application system and not directly into bodies of water.
Through the bypass, Crowell illegally discharged the liquid animal waste into a tributary of the French Broad River, which is used as a drinking water source and for recreational purposes and fishing.
"Michael regrets his poor judgment, and since the date of the offense has been working with environmental regulators to make sure nothing like this happens again," according to Stephen L. Cash, an attorney with the Asheville-based law firm of Cloninger, Barbour, Searson, Jones & Cash who represented the farm and Crowell.
Cash said in an email to Bloomberg BNA that Crowell has never before been convicted of a crime and "is glad to be able to put this matter behind him and glad that he has caused no lasting damage to the French Broad watershed."

Trump's Paris Exit Sidelines D.C. for Danes Blazing Wind Trail

Posted June 05, 2017, 11:21 A.M. ET
By Peter Levring

For Denmark, which relies more on wind energy than any other nation on the planet, June 1 was a pretty bad day.
The country's energy minister, Lars Chr. Lilleholt, watched in dismay as U.S. President Donald Trump extracted the world's biggest economy from the Paris accord, ignoring decades of science-based work that had guided political efforts to protect the globe from climate change.

But Lilleholt says the move also ignored the sound economics of renewable energy, and if the White House isn't listening, he's ready to take his message elsewhere.
The minister's next stop is China, where he'll discuss green energy this week at an event with about 20 other nations (representatives from the U.S. will also be there). Lilleholt says the view in Washington D.C. can't upend a movement that China, India and Europe all support. What's more, he expects American states to ignore Trump's agenda and continue using green energy. He says he's already received signals from local governments to that effect.
"It's my expectation that a number of U.S. states, east-coast states and Texas, among others, will continue to back this," Lilleholt said in an interview in Copenhagen. "Regardless what Trump says, the green transition will continue across the world, and in the U.S."
According to what the Danish government is hearing, Trump is likely to be isolated in his decision to abandon the Paris accord.
The pact still "looks solid," Lilleholt said. "The rest of the world stands together. The EU is united, we've heard from China, India, the U.K. I haven't heard of any other nations preparing to exit."
Lilleholt's travel itinerary sheds some light on the global leadership shift in an area that's proving more economically viable than fossil fuel production. Or, as Columbia University Professor Jeffrey Sachs puts it, Trump's decision to exit the Paris climate accord "is handing industrial leadership outside the U.S."
Denmark, which is home to Vestas Wind Systems A/S, the world's biggest wind-turbine maker, and Dong Energy A/S, the world's biggest offshore wind-park operator, has long played a prominent role in global renewable energy policies.
Vestas estimates that the U.S. wind industry "supports more than 100,000 jobs in 50 states, and it brings billions of dollars in economic development to the communities that host the projects," said Morten Dyrholm, a senior vice president for marketing at the company.
Denmark, which already gets about 40 percent of its electricity from wind power, is on target to have all its energy needs covered by renewables by 2050. Much of the new capacity will be built without subsidies. Lilleholt says Denmark's experience makes clear that coal is no longer cheaper to produce than renewable energy.
Lilleholt says Denmark will lobby hard in the European Union for the bloc to take a bigger role in the Paris accord now that the U.S. is out of the arrangement. He also said it was too much to expect the rest of the world to absorb the gap left by the U.S.
"We can't just distribute the U.S. obligations on 15 percent of the emissions to the other countries," he said.
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How Hard Will Pruitt Crack Down on Lake Erie Farmers?

Posted June 05, 2017, 7:01 A.M. ET

By David Schultz

The business of growing food in the upper Midwest may be about to significantly change.
An agreement reached last year between the U.S. and Canada may force state and federal officials to impose new limits on the amount of fertilizer that can be applied by farmers in parts of Ohio, Indiana, and Michigan. The two countries are seeking to halve the amount of nutrients, mostly from farms, that wash into Lake Erie. High levels of nutrients can cause algae blooms that contaminate the lake, an important drinking water source.
Some Lake Erie farmers have voluntarily adopted measures to reduce their fertilizer use and prevent the erosion of their topsoil. But, depending on how the binational process plays out, adopting those types of soil conservation measures may no longer become voluntary, something that deeply worries the local agriculture industry.
"Farmers are not big fans of regulation," Joe Cornely, a spokesman with the Ohio Farm Bureau, told Bloomberg BNA. "Decisions are best made locally."

Good Soil's Not Pretty

So what does it look like when a farmer adopts these soil conservation measures? In northwest Ohio, in early spring, one of these fields is not very pretty.
It's cold and wet, and the snowmelt has saturated the soil creating a dark black mud. A week or two before planting season, no one is working in the fields. Instead dead plants—an assortment of partially decomposed radishes, peas, oats and sunflowers—litter the untilled rows.
This farm belongs to Mike Libben, head of the local Soil and Water Conservation District in Ottawa County just outside of Toledo. Libben's farm may not be aesthetically pleasing, but everything he does is geared toward enriching his soil with nutrients and preventing it from washing away.

He's installed more efficient drainage systems that allow him to store water under his fields. He doesn't till his land, because that promotes erosion. And he plants cover crops—the radishes, peas, oats and sunflowers—which hold the soil in place and infuse it with nutrients after they decompose, reducing the need for more fertilizer.

An evangelist for this type of farming, Libben tries to persuade his neighbors through the conservation district to take similar measures. The goal is to reduce the amount of nutrient-laden sediment washing off into Lake Erie, the main source of drinking water for dozens of cities and towns, including Toledo.

Some farmers are receptive, he said, but others are stubbornly immune to his pitches. "It still always comes back to the cost," he told Bloomberg BNA. "'What's the bottom line for me? You want me to spend how many dollars and I don't get anything for it?' But it's the hidden benefits of it."

No Longer Voluntary?

The benefits of soil conservation become more clear when considering what happens when too much fertilizer washes off of farms and drains into Lake Erie. The fertilizer contains nutrients, primarily phosphorus, that are the primary cause of massive algae blooms that have plagued the western part of the lake in recent years.

A large algae bloom can suck all of the oxygen out of the water, creating hypoxic dead-zones where aquatic life can't survive.

And, under certain circumstances, these blooms can release toxins that are hard to detect in drinking water. In the summer of 2014, more than 400,000 residents in and around Toledo were told not to use their taps for three days after the city's water utility was surprised by an algae bloom that formed right in front of its intake pump inside Lake Erie.

Partly spurred on by this incident, the U.S. reached its agreement with Canada last year to reduce the amount of nutrients trickling into Lake Erie by 40 percent.

As a part of the Lake Erie agreement with Canada, which was signed less than a year before the end of the Obama administration, each country has to develop a set of actions to meet the 40 percent nutrient reduction target by February 2018.

Farm Runoff

While nutrients can come from many sources, such as sewers that carry human waste as well as phosphorus-rich detergents away from homes and businesses, farms contribute the overwhelming majority that winds up in Lake Erie and other bodies of water. More than 65 percent of the phosphorus in Lake Erie comes from farms, according to the Ohio Sea Grant.

And in northwest Ohio, farmland dominates the landscape. Nearly three quarters of the land that drains into the Maumee River, the largest western tributary into Lake Erie, is used for agriculture, according to the National Center for Water Quality Research.

But if this region has been farmed for generations, why are algae blooms suddenly a problem now? Climate change is one unavoidable reason, Gail Hesse, head of the National Wildlife Federation's Great Lakes program, said.

Lake Erie is the shallowest of the Great Lakes, and the lake is at its shallowest in its western third near Toledo. That means that rising air temperatures can more easily warm the water there, creating optimal conditions for algae growth. Additionally, even though farmers have become more efficient in applying fertilizer over the years, storms have also become more intense, washing more topsoil into the lakes.

Hesse said the Trump administration won't be able to avoid these facts when crafting its plan to get to 40 percent. "There's no way to achieve those targets without putting restrictions on agriculture in the western basin," she told Bloomberg BNA.

Agreement Moving Forward

At first glance, it would seem as if the Environmental Protection Agency, which is responsible for crafting the U.S. action plan, would have little appetite to take measures that dictate to farmers when and how they can apply fertilizer.

The new administration has consistently staked out pro-business positions on nearly every environmental issue and the agency's new leader, Scott Pruitt, was lauded with three standing ovations when he spoke at a Farm Bureau conference shortly after taking office.

But, so far, there's no evidence that the EPA is abandoning the Lake Erie agreement.

Wendy Carney, a deputy director in the EPA's Great Lakes regional office, said the agency is collaborating with the five states in the Lake Erie watershed on to come up with an action plan. She said they're on track to release a draft version this summer and then finalize it before the end of this year, several months ahead of schedule.

"Agricultural runoff is the top priority for management efforts, particularly in the Maumee River basin," Carney told Bloomberg BNA in an email.
Sandra George, one of Carney's counterparts across the border, also said the change in administrations in the U.S. has had no effect on the two countries' work.
"We still meet," George, a program coordinator in Canada's federal environmental agency, told Bloomberg BNA. "We're doing what we need to do."

'Fans of Regulation'

Cornely, the Ohio Farm Bureau spokesman, said he hopes the EPA takes into account all of the action on this issue that's been happening at the state and local levels. As an example, he pointed to the law Ohio Gov. John Kasich (R) signed in 2015 banning the application of fertilizer on frozen or saturated ground, when it's more susceptible to washing away.
Conditions across the Lake Erie watershed, from Toledo in the west to Buffalo in the east, vary so much that a top-down solution to the runoff problem is not feasible, he said.
"If the overall goal is for each of these government subdivisions to reach [a target], it seems to me to let each one of those entities figure out how to get there," Cornely said. "It's pretty rare that a one-size-fits-all regulation works."
But Cornely acknowledged that, if farmers want the EPA to go gentle on them in regulating runoff, they will need to show that they can deal with the problem themselves. This probably will involve more enthusiastic adoption of the kinds of soil conservation measures that Libben is trying to get his neighbors to adopt, he said.
"If you ask for the authority to stay local, it's incumbent upon you to come up with something that works," Cornely said. "Rights come accompanied by responsibility." This story was made possible in part by a fellowship with the Institute for Journalism & Natural Resources.

E-Commerce Boosts Demand for Brownfields Redevelopment

Posted June 05, 2017, 6:31 A.M. ET
By Sylvia Carignan

The e-commerce industry's appetite for warehouse space near major cities is boosting demand for brownfields as well as environmental insurance.
The trend is especially strong in New Jersey, where more than 50 percent of brownfields redevelopment projects are leased for online retail uses, according to commercial real estate firm Jones Lang LaSalle Inc. Other companies investing in brownfields for e-commerce include FedEx Corp., Under Armour Inc., and Wal-Mart Stores Inc.
With the increased demand for brownfields—which are often former industrial or commercial sites with environmental contamination—sites get cleaned up more quickly and can promote local economic growth.
"The demand has never been as high as it's been today," said Robert Kossar, who manages New Jersey operations for Jones Lang LaSalle Inc.
The same is true in other major metropolitan areas, according to Dan French, who is the chief executive officer of Brownfields Listings, which runs an online bulletin board for brownfields sites open for redevelopment and developers looking for sites.
He told Bloomberg BNA the current demand for warehouse space is "historic." "Land availability is getting tight in well developed locations, like say the I-55 corridor here in Chicagoland, but the demand for space just keeps growing," French said, referring to the Chicago metropolitan area.
"The consumer isn't slowing down and neither is e-commerce growth, so the buildup will go on."

Growing Insurance Demand

The demand for environmental insurance also has grown in the first half of 2017, said Glynis Priester, national practice leader in the environmental sector at Wells Fargo.
"On the growth front it is kind of a buyer's market, which I think is helping to drive new customers to buying environmental insurance," Priester told Bloomberg BNA. But there is strong interest in New Jersey from clients who are developing brownfields sites into warehouse space and need insurance coverage for environmental liabilities, Priester said.
"We are seeing a lot of developers who, in the past, really didn't have an appetite to acquire properties that were distressed, or saw a lot of contamination," she said. The high demand for real estate has turned that perspective around, despite the increased price of redeveloping a brownfield.
"Because there is such a dearth of available land, and because of the expense of that land, brownfield redevelopment has been the only means of redevelopment for this entire cycle," Kossar told Bloomberg BNA.
Ultimately, French said, brownfields benefit.

"The long-term trends are in place, industrial rents are [higher]," he said, "and it's great news for brownfield sites."

Investing in Brownfields

FedEx and Under Armour have signed leases to build distribution centers at the former Bethlehem Steel mill complex outside Baltimore.

Testing at the former steel mill showed the presence of lead, semi-volatile organic compounds, and polychlorinated biphenyls, among other contaminants. Cleanup efforts are proceeding under Maryland's voluntary cleanup program.

Offshore contamination near the site is being remediated under the Comprehensive Environmental Response, Compensation, and Liability Act, according to Maryland state documents.

According to Jones Lang LaSalle, the incentives for building at that site include a 10-year property tax credit, employment and job tax credits for being in the Chesapeake Enterprise Zone, and incentives from the regional power company.

FedEx chose the brownfield site "primarily because of its ease of access to major highways, proximity to customers' distribution centers and a strong local community workforce for recruiting employees," Meredith Heighington Miller, a spokeswoman for the company, said.

Under Armour referred Bloomberg BNA questions about the site to the developer.

French pushes brownfield owners in less popular markets to make their sites more appealing by preparing their sites for developers to start their work as soon as possible.

"If significant environmental issues need to be resolved, or a brownfield is early in the redevelopment process and not much information is known, then it can take longer than [developers] can afford to wait," he said.

China Is Said to Halt New Electric-Car Production Permits

Posted June 05, 2017, 11:25 A.M. ET

By Bloomberg News

China plans to halt issuing permits to produce electric vehicles pending a review of the policy because of concern additional approvals may lead to a glut in the world's biggest auto market, according to people familiar with the matter.

The National Development and Reform Commission, which oversees new investments in the auto industry, wants to evaluate the program after handing out 15 production licenses since March 2016, said the people, who asked not to be identified because the discussions aren't public. The NDRC didn't immediately respond to a faxed request for comment.

China has identified new-energy vehicles as a strategic emerging industry and aims to boost annual sales of plug-in hybrids and fully electric cars by 10-fold in the next decade. Besides giving generous subsidies for both consumers and manufacturers, the government created a class of permits allowing companies including billionaire Lu Guanqiu's Wanxiang Group and a Volkswagen AG joint venture to produce only electric vehicles, while imposing a moratorium on new capacity for the manufacture of conventional gasoline-run vehicles.

The state support helped China surpass the U.S. in 2015 to become the world's biggest market for new-energy vehicles—comprising electric vehicles, plug-in hybrids and fuel-cell cars. A total of 507,000 such vehicles were sold last year in the country, according to the China Association of Automobile Manufacturers.

While a suspension of new permits may delay plans by companies such as Internet entrepreneur William Li's NIO and Jia Yueting-backed LeEco's electric-car unit that have said they intend to apply, it may help incumbent electric-car manufacturers including BYD Co. and BAIC Motor Corp. by limiting the number of new entrants to the industry. Volkswagen's joint venture with Anhui Jianghuai Automobile Group Corp. received the 15th license to produce EVs.

To date, newly set up companies in China have announced at least 98 billion yuan ($14 billion) of investments to build electric car factories with a total annual capacity of 2.9 million units a year, or six times the number of plug-ins sold last year, according to data compiled by Bloomberg from company statements.

Apart from Karma Automotive owner Wanxiang Group, other companies that received the permits to manufacture electric vehicles include auto-parts maker Minth Group, car designer Beijing CH-Auto Technology Co., Beijing Electric Vehicle Co., Hangzhou Changjiang Passenger Vehicle Co. and a unit of Chery Automobile Co.

Chinese Premier Li Keqiang said last week the country will stick to its pledges to tackle global warming. President Donald Trump said he would withdraw the U.S. from the Paris climate pact

because it favored other nations, a move seen as an opening for China to burnish its image as a global leader on environment issues.
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Daily Environment Report for EPA

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Subject: RE: UOG POC: 7/25 minutes, 8/6 agenda and follow-up

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EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

This message may contain sensitive, privileged information covered by the deliberative process, attorney-client and/or attorney work product privileges. If you believe you have received this e-mail in error, please notify me and delete the e-mail immediately.

From: Parikh, Pooja <Parikh.Pooja@epa.gov>
Sent: Monday, August 05, 2019 11:19 AM
To: Branning, Amy <Branning.Amy@epa.gov>
Subject: FW: UOG POC: 7/25 minutes, 8/6 agenda and follow-up

Hi Amy – in the email below, there is a reference to Ex. 5 Deliberative Process (DP) / ACP
Ex. 5 Deliberative Process (DP) / ACP
Ex. 5 Deliberative Process (DP) / ACP Thanks!

From: Garvey, Megan <garvey.megan@epa.gov>
Sent: Monday, August 05, 2019 10:11 AM
To: Dressel, Paul <DRESSEL.PAUL@EPA.GOV>; Sharpe, Kristinn <Sharpe.Kristinn@epa.gov>; Byrne, Andrew <Byrne.Andrew@epa.gov>; Janifer, Pamela <Janifer.Pamela@epa.gov>; Passe, Loraine <Passe.Loraine@epa.gov>; Turk, David <Turk.David@epa.gov>; Kirby, Kevin <KIRBY.KEVIN@EPA.GOV>; Parikh, Pooja <Parikh.Pooja@epa.gov>; Elliott, Ross <Elliott.Ross@epa.gov>; Moskal, John <Moskal.John@epa.gov>; White, Terri-A <White.Terri-A@epa.gov>; Smith, Brian <Smith.Brian@epa.gov>; Hall, Richard <Hall.Richard@epa.gov>; Jann, Stephen <jann.stephen@epa.gov>; Lawrence, Rob <Lawrence.Rob@epa.gov>; Hildebrandt, Kurt <Hildebrandt.Kurt@epa.gov>; Albright, David <Albright.David@epa.gov>; Werntz, James <Werntz.James@epa.gov>; Matthews, Lisa <Matthews.Lisa@epa.gov>; Bates, William <bates.william@epa.gov>; Buckley, Katherine <Buckley.Katherine@epa.gov>; Remnek, Alexandre <Remnek.Alexandre@epa.gov>; Coffman, Joel <Coffman.Joel@epa.gov>; Curtis, Jennifer <Curtis.Jennifer@epa.gov>; Wright, Felicia <Wright.Felicia@epa.gov>; Pritts, Jesse <Pritts.Jesse@epa.gov>; Barbery, Andrea <Barbery.Andrea@epa.gov>; Hanson, Andrew <Hanson.Andrew@epa.gov>; Hesterlee, Craig <Hesterlee.Craig@epa.gov>; Bowles, Jack <Bowles.Jack@epa.gov>; Tierney, Meghan <Tierney.Meghan@epa.gov>; Conley, Alanna <conley.alanna@epa.gov>; Teichman, Kevin <Teichman.Kevin@epa.gov>; Mia, Marcia <Mia.Marcia@epa.gov>; Kobelski, Bruce <Kobelski.Bruce@epa.gov>; Hull, George <Hull.George@epa.gov>; Beeler, Cindy <Beeler.Cindy@epa.gov>; Noonan, Jenny <Noonan.Jenny@epa.gov>; Conley, Alanna <conley.alanna@epa.gov>; Kline, James <Kline.James@epa.gov>; Hambrick, Amy <Hambrick.Amy@epa.gov>; Davis, Alison <Davis.Alison@epa.gov>
Cc: Benevento, Douglas <benevento.douglas@epa.gov>; Cheatham-Strickland, Latonia <Cheatham-Strickland.Latonia@epa.gov>
Subject: UOG POC: 7/25 minutes, 8/6 agenda and follow-up

UOG POC:

Attached are the minutes from our July 25 call and a proposed agenda for the UOG POC call tomorrow. Let me know if you have any comments or questions.

I also address some follow-up matters below:

Someone asked about EPA's drone policy on the last call. Here's what I found out:

Ex. 5 Deliberative Process (DP)

Below are the states that joined New York in the lawsuit against EPA claiming unreasonable delay in establishing guidelines for methane emissions from existing oil and gas sources:

- STATE OF NEW YORK, STATE OF CALIFORNIA, STATE OF CONNECTICUT, STATE OF ILLINOIS, STATE OF IOWA, STATE OF MAINE, STATE OF MARYLAND, COMMONWEALTH OF MASSACHUSETTS, STATE OF NEW MEXICO, STATE OF OREGON, COMMONWEALTH OF PENNSYLVANIA, STATE OF RHODE ISLAND, STATE OF VERMONT, STATE OF WASHINGTON, DISTRICT OF COLUMBIA, CITY OF CHICAGO

Thanks, Megan

Megan E. Garvey
Senior Advisor for Oil and Gas, Regional Management and State Affairs
Office of the Administrator
U.S. Environmental Protection Agency
Work: 303.312.6192 | Cell: Ex. 6 Personal Privacy (PP)

Message

From: Branning, Amy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=A3F510CCED11492D88CC26ED073B7F10-ABRANNIN]
Sent: 3/13/2019 2:50:37 PM
To: Amy Hambrick (Hambrick.Amy@epa.gov) [Hambrick.Amy@epa.gov]; Marsh, Karen [Marsh.Karen@epa.gov]; Hoffman, Howard [hoffman.howard@epa.gov]; Fruh, Steve [Fruh.Steve@epa.gov]
Subject: FW: Budget hearing prep pagers - Due Wednesday noon
Attachments: Methane.docx

One observation I have is Ex. 5 Deliberative Process (DP) / ACP

Ex. 5 Deliberative Process (DP) / ACP

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

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From: Hambrick, Amy
Sent: Wednesday, March 13, 2019 10:00 AM
To: Fruh, Steve <Fruh.Steve@epa.gov>; Branning, Amy <Branning.Amy@epa.gov>; Hoffman, Howard <hoffman.howard@epa.gov>
Cc: Marsh, Karen <Marsh.Karen@epa.gov>
Subject: RE: Budget hearing prep pagers - Due Wednesday noon

Hi Steve- thanks. Ex. 5 Deliberative Process (DP) / ACP

Thanks for the opportunity,

Amy

Amy Hambrick
U.S. Environmental Protection Agency
(919)541-0964

From: Fruh, Steve
Sent: Wednesday, March 13, 2019 9:36 AM
To: Marsh, Karen <Marsh.Karen@epa.gov>; Hambrick, Amy <Hambrick.Amy@epa.gov>
Subject: Fwd: Budget hearing prep pagers - Due Wednesday noon

Sent from my iPhone

Begin forwarded message:

> **From:** "McLamb, Marguerite" <McLamb.Marguerite@epa.gov>
> **Date:** March 13, 2019 at 9:32:36 AM EDT
> **To:** "Fruh, Steve" <Fruh.Steve@epa.gov>
> **Subject: FW: Budget hearing prep pagers - Due Wednesday noon**
>
> Hi, Steve,
> Just a reminder that I need any comments on the methane pager before noon today, with OGC review.
> Thanks!
>
> ---
>
> **From:** McLamb, Marguerite
> **Sent:** Monday, March 11, 2019 11:26 AM
> **To:** Nick Hutson <Hutson.Nick@epa.gov>; King, Melanie <King.Melanie@epa.gov>; Steve Fruh <Fruh.Steve@epa.gov>; Lamason, Bill <Lamason.Bill@epa.gov>; Chuck French <French.Chuck@epa.gov>
> **Cc:** South, Peter <South.Peter@epa.gov>; Cozzie, David <Cozzie.David@epa.gov>
> **Subject:** FW: Budget hearing prep pagers - Due Wednesday noon
>
> Hi, all –
> PACS has asked for our review, coordinated with OGC, of the attached pagers by Wednesday at noon. The existing documents should be in pretty good shape. Please review them and have the appropriate OGC attorney provide feedback as well, and send me any comments you have by mid-morning on Wednesday.
> Thanks,
> Marguerite
>
> ---
>
> **From:** Ashley, Jackie
> **Sent:** Friday, March 08, 2019 3:37 PM
> **To:** McLamb, Marguerite <McLamb.Marguerite@epa.gov>; Terry, Sara <Terry.Sara@epa.gov>; Dolwick, Pat <Dolwick.Pat@epa.gov>; Hemby, James <Hemby.James@epa.gov>; Johnson, Yvonne W <Johnson.Yvonnew@epa.gov>; Bunte, Laura <Bunte.Laura@epa.gov>
> **Cc:** Noonan, Jenny <Noonan.Jenny@epa.gov>
> **Subject:** Budget hearing prep pagers - Due Wednesday noon
>
> All –
> OCIR is gathering hearing prep pagers for the upcoming budget hearings on April 2nd (House) and April 3rd (Senate). To support this effort, OAR IO would like us to coordinate with OGC to review and edit these fact sheets as needed by noon Wednesday (March 13).

Ex. 5 Deliberative Process (DP) / ACP

Please let me know if you have questions or will be unable to meet the deadline.

Thanks much,
Jackie

File Name	OAQPS Division
Ex. 5 Deliberative Process (DP) / ACP	Ex. 5 Deliberative Process (DP) / ACP

Jackie Ashley - US EPA - Office of Air Quality Planning and Standards - 919-541-7664 – ashley.jackie@epa.gov

Message

From: Branning, Amy [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=A3F510CCED11492D88CC26ED073B7F10-ABRANNIN]
Sent: 12/13/2017 2:35:55 PM
To: Branning, Amy [Branning.Amy@epa.gov]
Subject: RE: Pruitt Says EPA To Weigh Limiting Oil & Gas Methane In Pollutant 'Bundle'

Ex. 5 Deliberative Process (DP) / AWP

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

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From: Branning, Amy
Sent: Wednesday, December 13, 2017 9:34 AM
To: Zenick, Elliott <Zenick.Elliott@epa.gov>
Subject: FW: Pruitt Says EPA To Weigh Limiting Oil & Gas Methane In Pollutant 'Bundle'

Ex. 5 Deliberative Process (DP) See article

Amy Huang Branning
EPA Office of General Counsel
phone: (202) 564-1744
fax: (202) 564-5603 or (202) 564-0070

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From: Mia, Marcia
Sent: Wednesday, December 13, 2017 9:30 AM
To: Branning, Amy <Branning.Amy@epa.gov>
Subject: FW: Pruitt Says EPA To Weigh Limiting Oil & Gas Methane In Pollutant 'Bundle'

Marcia B Mia
Office of Compliance/Air Branch
2227A WJCS
U.S. Environmental Protection Agency
202-564-7042

From: Lawrence, Rob
Sent: Monday, December 11, 2017 6:59 PM

To: Beeler, Cindy <Beeler.Cindy@epa.gov>; Mia, Marcia <Mia.Marcia@epa.gov>
Subject: Fwd: Pruitt Says EPA To Weigh Limiting Oil & Gas Methane In Pollutant 'Bundle'

Ex. 5 Deliberative Process (DP)

Sent from my iPhone

Begin forwarded message:

From: "Casso, Ruben" <Casso.Ruben@epa.gov>
Date: December 11, 2017 at 4:13:19 PM CST
To: "Lawrence, Rob" <Lawrence.Rob@epa.gov>
Subject: Pruitt Says EPA To Weigh Limiting Oil & Gas Methane In Pollutant 'Bundle'

Pruitt Says EPA To Weigh Limiting Oil & Gas Methane In Pollutant 'Bundle'

December 11, 2017

EPA Administrator Scott Pruitt says the agency plans to weigh the "significant" question of whether to regulate oil and gas methane emissions directly or as part of a "bundle" of emissions including conventional air pollutants, the latter of which likely would foreclose any future standards of the potent greenhouse gas for existing equipment in the sector.

Pruitt during a House hearing last week noted that much of the current administration's work to date on the Obama EPA's first-time methane rules for new and modified oil and gas facilities has sought to pause looming compliance deadlines.

However, "as we go forward, the focus will be whether it needs to be part of a bundle or not" with other pollutants emitted by the sector such as volatile organic compounds (VOCs), he told a Dec. 7 hearing of the House Energy & Commerce Committee's environment panel.

The statement came in response to questions from Rep. Scott Peters (D-CA), who called the 2016 methane new source performance standards (NSPS) a "common-sense rule" because it simultaneously would boost energy supplies while reducing emissions of GHGs and other pollutants.

Pruitt noted that "historically" EPA has limited methane as a co-benefit of regulating VOCs from the sector. "What happened with that particular rule is the EPA for the first time pulled methane from that bundle and regulated it separately."

He added: "There is a meaningful debate and discussion that should occur as to whether the rule should be focused on a bundle approach, a VOC approach, or whether methane should be pulled out."

The administrator later said the "distinction matters" when looking at the "statutory framework" for regulating methane, and that it is a "significant question."

At the hearing, Pruitt did not elaborate on why the distinction is important.

He was likely referring to the fact that the NSPS, which governs new and modified facilities, creates a legal requirement for EPA to eventually regulate the potent GHG from existing sources in the oil and gas sector.

When EPA issues an NSPS under section 111(b) of the Clean Air Act, the statute says it "shall" also promulgate existing source standards for that pollutant and sector, which environmentalists pushed the Obama EPA to do immediately after the NSPS. However, the agency instead issued an information collection request to inform such a rule -- a request that Pruitt scrapped quickly after taking office.

EPA previously regulated the sector's VOCs through an NSPS that was issued in 2012.

However, the language of section 111(d) -- which governs existing source standards -- prohibits regulation of emissions of one of six "criteria" pollutants, as well as hazardous air pollutants.

VOCs are a precursor of ozone, which is a criteria pollutant, though methane falls into neither category.

That means that a "bundle" approach as floated by Pruitt would foreclose any future methane regulation of existing sources in the sector.

'Far Greater' Impacts

Critics of the Obama EPA's approach noted that its requirements controlled both VOCs and methane, and that EPA did not set "pollutant-specific controls" for methane.

"Even if EPA is correct that methane emissions from oil and gas sources create a public health issue or cause harm to the environment, it achieves all the stated goals through the regulation and control of VOC emissions," the Texas Pipeline Association said in comments on the proposed version of the NSPS, according to a response to comments document about EPA's decision to craft methane regulations.

And the American Petroleum Institute (API) in its comments noted that a final methane NSPS "would trigger an obligation for the Agency to issue emissions guidelines for existing oil and natural gas sources," and that such regulations "can and likely would have far greater potential impacts than" a new source rule.

The Obama EPA in the final rule said it was moving beyond VOC-only regulation, in which methane cuts are an "incidental benefit," because of the "current and projected future GHG emissions from the oil and natural gas industry" and the amount of emission cuts that could be achieved in a rule.

"The standards . . . will achieve meaningful GHG reductions and will be an important step towards mitigating the impact of GHG emissions on climate change," the agency said, adding that aligning rules for VOCs and methane would promote consistency for the industry and facilitate "implementation and enforcement."

Additionally, the group Clean Air Task Force said in its comments on the proposed NSPS that because of the structure of section 111, direct methane limits are "essential to fulfilling the agency's statutory obligation to reduce dangerous methane emissions from the oil and gas industry, including the most significant existing sources of that pollutant."

'Absolutely' A Pollutant

However, a different part of the House hearing exchange could also have bearing on whether EPA limits methane directly or as part of an emissions "bundle."

Peters referenced Pruitt's March appearance on CNBC in which he said carbon dioxide is not the "primary driver" of climate change and that it is not the only contributor.

"Do you agree that methane, nitrous oxide and other greenhouse gases are air pollutants?" he asked.

In response, Pruitt said: "Absolutely. And more potent, actually, than CO2. Methane is more potent than CO2, as you know, in that regard."

If the Trump EPA is reiterating past findings that methane is an "air pollutant," that could make it more difficult to scale back the methane-specific rules.

However, API and other industry critics of the rules also argued that the Obama EPA unlawfully failed to make a source-specific endangerment finding for the oil and gas sector's methane emissions, and also failed to show that such emissions "significantly contribute" to climate change

Message

From: Bowman, Liz [Bowman.Liz@epa.gov]
Sent: 7/17/2017 11:43:27 PM
To: Greaves, Holly [greaves.holly@epa.gov]; Fotouhi, David [fotouhi.david@epa.gov]; Schwab, Justin [schwab.justin@epa.gov]
Subject: RE: QFRs

Ex. 5 Deliberative Process (DP)

From: Greaves, Holly
Sent: Monday, July 17, 2017 7:40 PM
To: Fotouhi, David <fotouhi.david@epa.gov>; Schwab, Justin <schwab.justin@epa.gov>
Cc: Bowman, Liz <Bowman.Liz@epa.gov>
Subject: RE: QFRs

Thanks, please see my response to one comment below. Looping in Liz as she is doing some last minute editing.

From: Fotouhi, David
Sent: Monday, July 17, 2017 6:28 PM
To: Greaves, Holly <greaves.holly@epa.gov>; Schwab, Justin <schwab.justin@epa.gov>
Subject: RE: QFRs

Comments to your comments in blue text below. Thanks!

David Fotouhi

Deputy General Counsel
Office of General Counsel
U.S. Environmental Protection Agency
Tel: +1 202.564.1976
fotouhi.david@epa.gov

From: Greaves, Holly
Sent: Monday, July 17, 2017 1:14 PM
To: Fotouhi, David <fotouhi.david@epa.gov>; Schwab, Justin <schwab.justin@epa.gov>
Subject: RE: QFRs

Hi David/Justin, some additional questions for you as I review these. Please see below in red. Can you provide a response today? Thanks so much for your help with this!

From: Fotouhi, David
Sent: Monday, July 17, 2017 11:03 AM
To: Greaves, Holly <greaves.holly@epa.gov>
Subject: QRE: QFRs

Comments from Justin and me are below; let me know if you have any questions. Thanks!

Ex. 5 AC/DP

Ex. 5 AC/DP

Ex. 5 AC/DP

David Fotouhi

Deputy General Counsel
Office of General Counsel
U.S. Environmental Protection Agency
Tel: +1 202.564.1976
fotouhi.david@epa.gov

From: Fotouhi, David
Sent: Sunday, July 16, 2017 3:49 PM
To: Greaves, Holly <greaves.holly@epa.gov>
Subject: RE: QFRs

Sorry for the delay on this. Justin and I reviewed and have a few edits that I'll pass along tomorrow morning.

David Fotouhi

Deputy General Counsel
Office of General Counsel
U.S. Environmental Protection Agency
Tel: +1 202.564.1976
fotouhi.david@epa.gov

From: Greaves, Holly
Sent: Tuesday, July 11, 2017 4:47 PM
To: Fotouhi, David <fotouhi.david@epa.gov>
Cc: Schwab, Justin <schwab.justin@epa.gov>
Subject: RE: QFRs

Thanks - they will go to OMB before going to the Hill next Tuesday, Ex. 5 AC/DP
Ex. 5 AC/DP I appreciate your help!

From: Fotouhi, David
Sent: Tuesday, July 11, 2017 4:46 PM
To: Greaves, Holly <greaves.holly@epa.gov>
Cc: Schwab, Justin <schwab.justin@epa.gov>
Subject: Re: QFRs

Ex. 5 AC/DP

Sent from my iPhone

On Jul 11, 2017, at 4:42 PM, Greaves, Holly <greaves.holly@epa.gov> wrote:

> Hi Justin/David, did you by chance have time to look at the QFRs from a legal perspective? They are going to OMB tomorrow.
>
> Thanks,
> Holly

Message

From: Fotouhi, David [fotouhi.david@epa.gov]
Sent: 7/17/2017 11:42:12 PM
To: Greaves, Holly [greaves.holly@epa.gov]; Schwab, Justin [schwab.justin@epa.gov]
CC: Bowman, Liz [Bowman.Liz@epa.gov]
Subject: RE: QFRs

Great; thanks! Liz, let me know if you need to run anything by me.

David Fotouhi

Deputy General Counsel
Office of General Counsel
U.S. Environmental Protection Agency
Tel: +1 202.564.1976
fotouhi.david@epa.gov

From: Greaves, Holly
Sent: Monday, July 17, 2017 7:40 PM
To: Fotouhi, David <fotouhi.david@epa.gov>; Schwab, Justin <schwab.justin@epa.gov>
Cc: Bowman, Liz <Bowman.Liz@epa.gov>
Subject: RE: QFRs

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Subject: RE: QFRs

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fotouhi.david@epa.gov

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To: Fotouhi, David <fotouhi.david@epa.gov>; Schwab, Justin <schwab.justin@epa.gov>
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Subject: QRE: QFRs

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Ex. 5 AC/DP

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Office of General Counsel
U.S. Environmental Protection Agency
Tel: +1 202.564.1976
fotouhi.david@epa.gov

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To: Greaves, Holly <greaves.holly@epa.gov>
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fotouhi.david@epa.gov

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Sent: Tuesday, July 11, 2017 4:47 PM
To: Fotouhi, David <fotouhi.david@epa.gov>
Cc: Schwab, Justin <schwab.justin@epa.gov>
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To: Greaves, Holly <greaves.holly@epa.gov>
Cc: Schwab, Justin <schwab.justin@epa.gov>
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Ex. 5 AC/DP

Sent from my iPhone

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> Thanks,
> Holly

Message

From: Fotouhi, David [fotouhi.david@epa.gov]
Sent: 7/17/2017 10:27:32 PM
To: Greaves, Holly [greaves.holly@epa.gov]; Schwab, Justin [schwab.justin@epa.gov]
Subject: RE: QFRs

Comments to your comments in blue text below. Thanks!

David Fotouhi

Deputy General Counsel
Office of General Counsel
U.S. Environmental Protection Agency
Tel: +1 202.564.1976
fotouhi.david@epa.gov

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Office of General Counsel
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fotouhi.david@epa.gov

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To: Fotouhi, David <fotouhi.david@epa.gov>
Cc: Schwab, Justin <schwab.justin@epa.gov>
Subject: RE: QFRs

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Sent: Tuesday, July 11, 2017 4:46 PM
To: Greaves, Holly <greaves.holly@epa.gov>
Cc: Schwab, Justin <schwab.justin@epa.gov>
Subject: Re: QFRs

Ex. 5 AC/DP

Sent from my iPhone

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Thanks,
Holly

Message

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Sent: 7/17/2017 5:14:03 PM
To: Fotouhi, David [fotouhi.david@epa.gov]; Schwab, Justin [schwab.justin@epa.gov]
Subject: RE: QFRs

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To: Greaves, Holly <greaves.holly@epa.gov>
Subject: QRE: QFRs

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Ex. 5 AC/DP

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To: Greaves, Holly <greaves.holly@epa.gov>
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Thanks - they will go to OMB before going to the Hill next Tuesday, Ex. 5 AC/DP
Ex. 5 AC/DP I appreciate your help!

From: Fotouhi, David
Sent: Tuesday, July 11, 2017 4:46 PM
To: Greaves, Holly <greaves.holly@epa.gov>
Cc: Schwab, Justin <schwab.justin@epa.gov>
Subject: Re: QFRs

Ex. 5 AC/DP

Sent from my iPhone

On Jul 11, 2017, at 4:42 PM, Greaves, Holly <greaves.holly@epa.gov> wrote:

> Hi Justin/David, did you by chance have time to look at the QFRs from a legal perspective? They are going to OMB tomorrow.
>
> Thanks,
> Holly

Message

From: Witt, Jon [/O=EXCHANGELABS/OU=EXCHANGE ADMINISTRATIVE GROUP (FYDIBOHF23SPDLT)/CN=RECIPIENTS/CN=EA00BC6F645B438682026A77A8D4267C-WITT, JONAT]
Sent: 3/15/2018 6:40:01 PM
To: Kaleri, Cynthia [kaleri.cynthia@epa.gov]
Subject: RE: Texas fugitives requirements

No apologies necessary! This is why we have a workgroup ☺
Jonathan

From: Kaleri, Cynthia
Sent: Thursday, March 15, 2018 1:44 PM
To: Witt, Jon <Witt.Jon@epa.gov>
Subject: RE: Texas fugitives requirements

Hi Jon,

Ex. 5 Deliberative Process (DP)

Thanks,

Cynthia J. Kaleri
Enforcement Officer, EPA Region 6

Phone (214) 665-6772
Mailing Address
Attention: Cynthia J. Kaleri (6EN-AA)
United States Environmental Protection Agency
1445 Ross Avenue
Dallas, TX 75202-2733

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From: Witt, Jon
Sent: Thursday, March 15, 2018 11:54 AM
To: Kaleri, Cynthia <kaleri.cynthia@epa.gov>
Subject: RE: Texas fugitives requirements

Hi Cyndi,

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Thanks again for taking a look through! Please let me know if you have any further questions or if there's anything I missed.

Jonathan

From: Kaleri, Cynthia
Sent: Thursday, March 15, 2018 12:02 PM
To: Witt, Jon <Witt.Jon@epa.gov>
Subject: RE: Texas fugitives requirements

Hi Jon,

Ex. 5 Deliberative Process (DP)

Cynthia J. Kaleri
Enforcement Officer, EPA Region 6

Phone (214) 665-6772
Mailing Address
Attention: Cynthia J. Kaleri (6EN-AA)
United States Environmental Protection Agency
1445 Ross Avenue
Dallas, TX 75202-2733

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From: Witt, Jon
Sent: Tuesday, March 13, 2018 4:52 PM
To: Kaleri, Cynthia <kaleri.cynthia@epa.gov>
Subject: RE: Texas fugitives requirements

Ex. 5 Deliberative Process (DP)

Thanks again,
Jonathan

From: Kaleri, Cynthia
Sent: Tuesday, March 13, 2018 4:28 PM
To: Witt, Jon <Witt.Jon@epa.gov>
Subject: RE: Texas fugitives requirements

Hi Jon,

Ex. 5 Deliberative Process (DP)

I don't know if this helps! Sorry,

Cynthia J. Kaleri
Enforcement Officer, EPA Region 6

Phone (214) 665-6772
Mailing Address
Attention: Cynthia J. Kaleri (6EN-AA)
United States Environmental Protection Agency
1445 Ross Avenue
Dallas, TX 75202-2733

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From: Witt, Jon
Sent: Monday, March 12, 2018 10:00 AM
To: Kaleri, Cynthia <kaleri.cynthia@epa.gov>
Subject: RE: Texas fugitives requirements

Hi Cyndi,

I had another question a Ex. 5 Deliberative Process (DP)
Ex. 5 Deliberative Process (DP)

Thanks,
Jonathan

From: Witt, Jon
Sent: Thursday, March 01, 2018 12:04 PM
To: Kaleri, Cynthia <kaleri.cynthia@epa.gov>
Subject: RE: Texas fugitives requirements

Hi Cindy,

Thanks for sending these along! These are really helpful. I think it's starting to become a little more clear. I had a few more questions on the different permit (and non-permit) types:

Ex. 5 Deliberative Process (DP)

Let me know if I mischaracterized anything. We can also chat about this over the phone if you would prefer.

Thanks again,
Jonathan

From: Kaleri, Cynthia
Sent: Wednesday, February 28, 2018 4:31 PM
To: Witt, Jon <Witt.Jon@epa.gov>
Subject: RE: Texas fugitives requirements

Hi Jon,

Ex. 5 Deliberative Process (DP)

Cynthia J. Kaleri
Enforcement Officer, EPA Region 6

Phone (214) 665-6772
Mailing Address
Attention: Cynthia J. Kaleri (6EN-AA)
United States Environmental Protection Agency
1445 Ross Avenue
Dallas, TX 75202-2733

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From: Witt, Jon
Sent: Wednesday, February 28, 2018 2:28 PM
To: Kaleri, Cynthia <kaleri.cynthia@epa.gov>
Subject: Texas fugitives requirements

Hi Cynthia,

Ex. 5 Deliberative Process (DP)

Ex. 5 Deliberative Process (DP)

Let me know if any of these interpretations are incorrect and if you'd like to set up a meeting to talk more about these.

Thanks so much,
Jonathan

Jonathan W. Witt, EI
Environmental Engineer
Office of Air Quality Planning and Standards
EPA|OAR|OAQPS|SPPD|FIG
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