NOT YET SCHEDULED FOR ORAL ARGUMENT

No. 20-1360 and consolidated cases

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

ENVIRONMENTAL DEFENSE FUND, et al.,
Petitioners,

v.

ANDREW WHEELER, et al.,
Respondents.

On Petition for Review of Final Agency Action of the
United States Environmental Protection Agency

RESPONDENTS' MEMORANDUM IN OPPOSITION TO MOTION FOR PARTIAL STAY PENDING REVIEW

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GLOSSARY

CAA	Clean Air Act
EPA	Environmental Protection Agency
Final Rule Technical Support	Background Technical Support Document for the Final Reconsideration of the New Source Performance Standards 40 CFR Part 60, subpart OOOOa (Aug. 2020), Docket ID No. EPA-HQ-OAR-2017-0483-2290
Policy Rule	Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review, 85 Fed. Reg. 57,018 (Sept. 14, 2020)
Responses	Responses to Public Comments on Proposed Rule [83 FR 52056, October 15, 2018], Docket ID No. EPA-HQ-OAR-2017-0483-2291
Regulatory Impact Analysis	Regulatory Impact Analysis for the Review and Reconsideration of the Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources (Aug. 2020), Docket ID No. EPA-HQ-OAR-2017-0483-2295
Section 7411	42 U.S.C. § 7411
Technical Rule	Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration, 85 Fed. Reg. 57,398 (Sept. 15, 2020)
VOC	Volatile organic compounds
2016 Rule	Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule, 81 Fed. Reg. 35,824 (June 3, 2016)

INTRODUCTION

This case presents highly technical, record-based challenges to an EPA rule modifying Clean Air Act New Source Performance Standards for the oil and gas industry. Petitioners seek a "partial stay" of certain provisions governing oil and gas sources' requirements to monitor "fugitive emissions." But Petitioners have not met their heavy burden of showing that they are likely to prevail on the merits. EPA's rulemaking determinations were based on careful consideration of data on costs and emissions reductions and analysis of cost-effectiveness. Petitioners identify no failure to explain or "error" in EPA's justifications, but rather disagree with the conclusions EPA drew from the data. Thus, Petitioners fail to show they are "likely" to overcome the extreme deference the Court traditionally gives to EPA's expertise in making such technical determinations.

Petitioners also fail to demonstrate that the monitoring requirements in this rule will cause "irreparable harm" of the certainty and magnitude necessary to justify a stay under this Court's jurisprudence. The evidence on which Petitioners premise their harm allegations cannot sustain their burden because it incorporates unfounded assumptions that likely overstate Petitioners' estimates of the rule's impact in terms of foregone emission reductions. Conversely, Petitioners have not even attempted to show that the much lower impacts EPA estimates will cause irreparable harm. Moreover, even if Petitioners' unreliable estimates were correct, when considered in context the overall magnitude of the foregone emissions reductions Petitioners claim will occur is far smaller than their motion makes it appear, and thus fails to support their argument that extraordinary relief is necessary.

Finally, consideration of the public interest and that of other stakeholders, including regulated sources that will incur greater compliance costs during the pendency of these petitions if the rule is partially stayed, outweighs Petitioners' speculative harm allegations. For all of these reasons, the Court should deny this motion and allow the litigation to proceed in the usual course.

BACKGROUND

A. Statutory background

The Clean Air Act ("CAA"), 42 U.S.C. §§ 7401-7671q, creates a comprehensive program for control of air pollution. Under Section 7411, EPA must identify categories of sources that the Administrator has determined "cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare." *Id*. § 7411(b)(1)(A).

EPA then sets federal "standards of performance" for constructed, modified, and reconstructed sources (collectively, "new sources") in each category. *Id*. § 7411(a)(2), (b)(1)(B); 40 C.F.R. § 60.15. EPA refers to these as "new source performance standards." They are based on the "best system of emissions reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." 42 U.S.C. § 7411(a)(1). EPA reviews, and if appropriate, revises the standards periodically. *Id.* § 7411(b)(1)(B).

B. Regulatory background

1. Prior regulations

EPA first listed "Crude Oil and Natural Gas Production" as a Section 7411 source category in 1979. 44 Fed. Reg. 49,222, 49,226 (Aug. 21, 1979). EPA then promulgated two initial Section 7411 rules. 50 Fed. Reg. 26,122 (June 24, 1985); 50 Fed. Reg. 40,158 (Oct. 1, 1985). In 2012, EPA reviewed and revised these standards. 77 Fed. Reg. 49,490 (Aug. 16, 2012).

In 2016, after considering administrative reconsideration petitions, EPA further amended the regulations to include standards for reducing methane across the oil and natural gas industry (*i.e.*, production, processing, transmission and storage), as well as additional standards for emissions of volatile organic compounds ("VOC"). 81 Fed. Reg. 35,824, 35,825 (June 3, 2016) ("2016 Rule"). EPA anticipated that the 2016 standards would incidentally reduce certain "hazardous air pollutants" that are separately regulated under 42 U.S.C. § 7412. But EPA did not consider the reduction of hazardous air pollutants when determining the best system of emission reduction for the pollutants it addressed under Section 7411.

EPA subsequently granted petitions for administrative reconsideration of certain aspects of the 2016 Rule and stayed those portions of the rule pending reconsideration. 82 Fed. Reg. 25,730 (June 5, 2017). This Court vacated the stay. *Clean Air Council v. Pruitt*, 862 F.3d 1, 4 (D.C. Cir. 2017).

2. EPA's Technical Rule

In September 2020, EPA finalized two new rules. First, a "Policy Rule" removed the transmission and storage segment from the listed source category and rescinded standards for that segment based on EPA's conclusion that transmission and storage operations are distinct from other sources in this category and that EPA presently lacks authority to regulate transmission and storage operations under Section 7411. 85 Fed. Reg. 57,018, 57,027-30 (Sept. 14, 2020). Separately, the Policy Rule rescinded the methane standards applicable to the production and processing segments. EPA concluded that these standards were unnecessary because they were duplicative of the VOC standards, and because EPA lacked authority to establish methane standards based on the findings it had made to date. *Id*. at 57,030-40.

The second rule is under review here. In this "Technical Rule," EPA revised a number of technical requirements for the source category based on the Agency's reconsideration of the 2016 Rule. 85 Fed. Reg. 57,398 (Sept. 15, 2020). Of relevance to this motion are particular revisions relating to requirements for monitoring fugitive emissions from low production well sites[1] and gathering and boosting compressor stations,[2] respectively. 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. Declaration of Anne Austin ("Austin Decl.") ¶ 13.

a. Fugitive emissions monitoring at low production well sites

The 2016 Rule required semiannual monitoring for fugitive emissions at oil and gas production well sites. *See* 85 Fed. Reg. at 57,405. The petitions for administrative reconsideration of the 2016 Rule sought several changes to these requirements, including an exemption for low production well sites. 83 Fed. Reg. 52,056, 52,062 (Oct. 15, 2018). In its 2018 reconsideration proposal, EPA explained that it may have overestimated both emissions and the potential for emissions reductions from low production well sites in the 2016 Rule. *Id*. at

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[1] A low production well site is a well site with total production at or below 15 barrels of oil equivalent per day. *Id*. at 57,412.

[2] A "compressor station" refers to any permanent combination of one or more compressors that move natural gas at increased pressure through gathering pipelines. 40 C.F.R. § 60.5430a.

52,068. As a result, EPA explained that it may also have overestimated the cost-effectiveness of the various monitoring frequencies it had analyzed. *Id.* at 52,062. EPA then explained in detail how it had revised its 2016 analysis based on its review of the data and solicited comments on its proposed changes to the monitoring requirements, including all substantive aspects of its analysis. *Id.* at 52,062-69. EPA specifically "solicit[ed] comment and supporting data on an exemption from fugitive emissions requirements at low production well sites." *Id.* at 52,069.

After considering the public comments, EPA concluded in the Technical Rule that the data and supporting analysis justified an exemption of low production well sites from fugitive emissions monitoring, provided that the owners and operators maintain certain records to demonstrate that total well site production is at or below 15 barrels of oil equivalent per day. 85 Fed. Reg. at 57,400, 57,405. For other well sites, the Technical Rule generally maintains the semiannual monitoring required by the 2016 Rule. *Id.* at 57,405.

b. Fugitive emissions monitoring at compressor stations

The 2016 Rule also required fugitive emissions monitoring at compressor stations, of which there are several types, including gathering and boosting compressor stations, transmission stations, and storage stations. *See* 85 Fed. Reg. at 57,420. In 2016, EPA had determined that quarterly monitoring was cost-effective for compressor stations based on the weighted average of the cost-effectiveness values for all of those station types. *Id*. at 57,420-21. Administrative reconsideration petitioners provided data to EPA that, according to those petitioners, showed monitoring at compressor stations should be required less frequently. 83 Fed. Reg. at 52,069. In response, EPA considered the data and conducted a sensitivity analysis to better understand how a range of monitoring frequencies would affect emission reductions and costs at compressor stations, including quarterly, semiannual and annual monitoring. *Id.* at 52,069-71.

In its 2018 proposed rule, EPA co-proposed either semiannual or annual monitoring at compressor stations while seeking "comment and supporting information related to our analysis of the information, including data that sheds further light on which monitoring frequency (annual, semiannual, or quarterly) is most appropriate." *Id.* at 52,071. In the Technical Rule, EPA changed its focus to the appropriate monitoring frequency for gathering and boosting compressor stations because, after the finalization of the Policy Rule, transmission and storage compressor stations were no longer part of the source category. 85 Fed. Reg. at 57,421. Based on EPA's analysis of the average and incremental cost-effectiveness values for the various monitoring frequencies and other factors relevant to cost, EPA concluded that semiannual monitoring should be required for fugitive emissions from gathering and boosting compressor stations. *Id.*

C. Procedural background

Multiple petitions for judicial review of the Policy Rule were filed and consolidated, and those petitioners sought both a stay pending review and summary vacatur. *See California v. Wheeler*, No. 20-1357 consolidated with 20-1359 and 20-1363 (D.C. Cir.). On October 27, 2020, the Court issued a *per curiam* order holding that "[t]he merits of the parties' positions" on the Policy Rule "are not so clear as to warrant summary action," and that the petitioners "have not satisfied the stringent requirements for a stay." ECF No. 1868350 in No. 20-1357 at 1-2. Merits briefing is in progress and no argument date has been set. *Id.* at 3.

Multiple petitions for review of the Technical Rule also were filed and consolidated. On November 13, 2020, environmental group Petitioners filed the instant motion to stay the rule's provision on fugitive emissions monitoring at compressor stations and its exemption of low production well sites from such monitoring. ECF No. 1871182 (hereinafter "Motion").

STANDARD OF REVIEW

A judicial stay of an agency decision is a disfavored remedy. The movant must "justify the court's exercise of such an extraordinary remedy." *Cuomo v. U.S. Nuclear Regulatory Commission*, 772 F.2d 972, 978 (D.C. Cir. 1985). The factors for determining whether a judicial stay is warranted are: (1) the likelihood that the moving party will prevail on the merits; (2) the prospect of irreparable injury to the moving party; (3) the possibility of harm to other parties; and (4) the public interest. *Id*. at 974; *see* Circuit Rule 18. Courts apply this standard stringently. *Nken v. Holder*, 556 U.S. 418, 434 (2009).

To demonstrate a likelihood of success on the merits, Petitioners must show they are likely to persuade this Court that EPA's action is "arbitrary, capricious, an abuse of discretion, or otherwise not in accordance with law." 42 U.S.C. § 7607(d)(9)(A). The "arbitrary or capricious" standard presumes the validity of agency actions, and a reviewing court is to uphold an agency action that satisfies minimum standards of rationality. *Small Refiner Lead Phase-Down Task Force v. EPA*, 705 F.2d 506, 520-21 (D.C. Cir. 1983). Where EPA has considered the relevant factors and articulated a rational connection between the facts found and the choices made, its regulatory choices must be upheld. *Motor Vehicle Manufacturers Ass'n v. State Farm Mutual Automobile Insurance Co.*, 463 U.S. 29, 43 (1983). EPA is also entitled to an "extreme degree of deference [] when it is evaluating scientific data within its technical expertise." *City of Waukesha v. EPA*, 320 F.3d 228, 247 (D.C. Cir. 2003) (internal quotation marks omitted). "Such deference is especially appropriate in [the Court's] review of EPA's administration of the complicated provisions of the Clean Air Act." *Catawba County, NC. v. EPA*, 571 F.3d 20, 41 (D.C. Cir. 2009) (citations omitted).

To establish irreparable harm, Petitioners must demonstrate injury that is "both certain and great; it must be actual and not theoretical." *Wisconsin Gas Co. v. Federal Energy Regulatory Commission*, 758 F.2d 669, 674 (D.C. Cir. 1985). A mere possibility of such harm is insufficient. *Winter v. NRDC*, 555 U.S. 7, 20-24 (2008).

ARGUMENT

I. Petitioners are not likely to succeed on the merits.

Petitioners demonstrate no likelihood of success on the merits. EPA articulated sound reasons for determining that fugitive emissions monitoring should not be required at low production well sites and that semiannual monitoring should be required at compressor stations. EPA further identified the record data and analysis supporting its decisions. This is *not* a case where Petitioners have shown that EPA overlooked a required statutory factor or failed to explain its rationale. And to the extent Petitioners second-guess EPA's conclusions about cost-effectiveness or details regarding the data or analytical methodology EPA used, these criticisms fall squarely within the realm where an "extreme degree of deference" is afforded to EPA's technical and scientific expertise. *City of Waukesha*, 320 F.3d at 247.

A. EPA reasonably determined that fugitive emissions monitoring was not required for low production well sites.

On reconsideration, EPA reviewed additional data and performed further analysis regarding the cost-effectiveness of fugitive emissions monitoring. In the final rule, EPA then provided a reasoned explanation for determining that semiannual monitoring remains cost-effective and appropriate at non-low production well sites, but *not* at low production well sites. Specifically, EPA reasonably found that "none of the monitoring frequencies are cost effective for low production well sites." 85 Fed. Reg. at 57,419. Therefore, EPA appropriately exempted low production well sites from fugitive emissions monitoring. *Id.* at 57,419-21.

As EPA explained, in the 2016 rulemaking, EPA had not performed a separate cost-effectiveness evaluation for low production well sites. *Id.* at 57,419. In 2016, "EPA believe[d] that well site fugitive emissions are not correlated with levels of production, but rather based on the number of pieces of equipment and components." 81 Fed. Reg. at 35,856. EPA assumed, therefore, "that the fugitive emissions from low production and non-low production well sites are comparable." *Id.*

For the 2020 rulemaking, EPA re-evaluated this issue. Specifically, EPA revised its model plant analysis, on which the 2016 Rule had relied, to account for information it received or re-evaluated during reconsideration. 85 Fed. Reg. at 57,419; *see id.* at 57,417-18 (summarizing updates to the model plant). For example, EPA determined that new information, as well as the Agency's re-evaluation of an existing study (the "Fort Worth Study," *infra* at 14-16), supported a reduction in the assumed number of pieces of equipment and components at low production well sites. *Id*. at 57,417. After making these revisions to the model plant analysis, it showed that "there is sufficient evidence that low production well sites are different than well sites with higher production and, therefore, warrant a separate evaluation of the cost of control." *Id.* at 57,419.

EPA then performed a separate cost-effectiveness analysis of fugitive emissions monitoring for low production well sites. EPA found that the cost-effectiveness of fugitive emissions monitoring at low production wells would be $6,061/ton of VOC emissions removed if monitoring is performed biennially, $6,116/ton if performed semiannually, and $7,577/ton if performed annually. *Id.* EPA observed that "[a]ll of these values are higher than the inflation-adjusted value of $5,459/ton VOC that was estimated for semiannual monitoring at well sites in 2016." *Id.* Moreover, all of these values were higher than the $5,700/ton value that EPA had found was *not* cost-effective in prior rulemakings, including the 2016 Rule. *Id.* at 57,419 & n.54; *see* 80 Fed. Reg. 56,693 56,636 (Sept. 18, 2015), *discussing* 72 Fed. Reg. 64,860, 64,864 (Nov. 16, 2007). Therefore, EPA reasonably "determined that none of the monitoring frequencies are cost-effective for low production well sites." 85 Fed. Reg. at 57,419; *see also id.* at 57,412-20 & Table 4 (describing data and analysis), 57,427-29 (summarizing comment responses).

Petitioners identify no "error" or failure of EPA to explain its rationale that would warrant setting aside EPA's determination. Petitioners initially note EPA's obligation to identify "a rational basis for treating some sources in the regulated category differently," Motion at 16, but EPA met this obligation. As summarized above, EPA explained how the record on reconsideration showed that low production well sites were distinct from other well sites both in terms of their fugitive emissions characteristics and the cost-effectiveness of monitoring those emissions. While Petitioners may *disagree* with the conclusions EPA drew from the data, EPA's explanation of its analysis and conclusions shows that it "considered all relevant factors" and identified the "rational connection between the facts found and the choice made" that the arbitrary-and-capricious standard requires. *Catawba County*, 571 F.3d at 41.

Petitioners also decry EPA's reliance on a model plant analysis instead of "actual emissions data." Motion at 17. Yet Petitioners concede, as they must, that the model plant methodology is "commonly used by EPA to estimate emissions," and indeed it was the approach EPA used in 2016. *Id.* at 18.

Petitioners identify four specific criticisms of the 2020 model plant analysis, none of which suggests that Petitioners are "likely to succeed on the merits." First, they contend that EPA acted arbitrarily in its re-evaluation of the Fort Worth Study because it "considered only the study's data on component counts" while purportedly "ignoring" actual emissions data reported in the study. Motion at 18; *see* 85 Fed. Reg. at 57,417. EPA did not ignore the actual emissions data. Rather, as EPA explained in response to comments, it analyzed both component counts and emissions data reported in the study and found "a statistical difference between the emissions of non-low and low production well sites," warranting a separate analysis for low production well sites. EPA Responses to Public Comments, Docket ID No. EPA-HQ-OAR-2017-0483-2291 ("Responses") at 8-70. EPA has consistently used component counts to develop fugitive emissions model plants, including in its analysis for the 2016 Rule. *See* 81 Fed. Reg. at 35,856.

Petitioners' next two criticisms are that EPA purportedly failed to explain how well sites in the Fort Worth Study were representative of low production well sites nationwide, and "cherry-picked" 16 of those well sites while excluding 11 others. Motion at 19-21. The record shows otherwise. On the first point, EPA concluded that the Fort Worth Study was the best available data for the purpose of modeling low production well sites. Responses at 8-71. Due to the limitations and uncertainties associated with other available data, as described in EPA's analysis,[3] EPA concluded that these other data "were not sufficient to directly modify low production model plants." Final Rule Technical Support, No. EPA-HQ-OAR-2017-0483-2290, at 10. However, far from ignoring these other data, EPA used them to re-examine and re-analyze the Fort Worth study, and updated the model plant accordingly. *Id.* at 10-11.

EPA also explained its reasons for using only 16 rather than 27 well sites from the Fort Worth Study. As EPA noted, after it initially used the larger group of well sites from that study to update its model plant analysis for the 2018 proposed rule, it then reexamined the study in response to comments on the proposal. *Id.* at 10. As a result of this reexamination, it removed any well site reporting zero production because that "may have been due to any number of reasons not related to the actual normal production at the site (e.g., well shut-in)." *Id.* at 11. This left 16 remaining well sites in the data set for modeling low production well sites. *Id.* Petitioners claim that because only one day of production data was reported for each well site, it is possible that operation

[3] Memorandum, Summary of Data Received on the October 15, 2018 Proposed Amendments to 40 CFR Part 60, Subpart OOOOa Related to Model Plant Fugitive Emissions (Feb. 10, 2020), EPA-HQ-OAR-2017-0483-2290, attachment 1.

conditions on that day were abnormal. Motion at 21. Nonetheless, it was reasonable and not "arbitrary" for EPA to assume that zero-production days were less likely than others to be operationally representative, and Petitioners fail to show that using the 16 wells with greater than zero production rather than all 27 materially affected EPA's cost-effectiveness conclusions.

Finally, Petitioners argue that EPA should have accounted for methane emissions reductions in its cost-effectiveness analysis. But as noted above, EPA rescinded the methane standards in the Policy Rule. *Supra* at 4. Regardless, EPA's analysis found that the cost per ton of methane reductions for low production wells, at all of the monitoring frequencies evaluated, was more than double the cost it had estimated in the 2016 analysis (which did not separately evaluate low production wells). 85 Fed. Reg. at 57,420. Thus, EPA explained, "even if we had not rescinded the methane standards [], we would still conclude that fugitive emissions monitoring, at any of the frequencies evaluated, is not cost effective for low production well sites." *Id.*

B. EPA reasonably required semiannual fugitive emissions monitoring for compressor stations.

EPA also reasonably determined that semiannual rather than quarterly fugitive emissions monitoring should be required for compressor stations. EPA appropriately updated its model plant analysis to focus specifically on emission reductions and associated costs at gathering and boosting compressor stations. 85

Fed. Reg. at 57,421. EPA considered both the average and incremental cost-effectiveness values for each monitoring frequency. *Id.* EPA found, in particular, that the incremental reductions achievable by increasing from annual monitoring to semiannual monitoring were comparable to those achievable by increasing from semiannual monitoring to quarterly monitoring, but were far less costly. *Id.* EPA also considered the potential cost savings and efficiencies from requiring monitoring on the same frequency as for non-low production well sites—*i.e.*, semiannually—and the impact of financial hardship on operations in the source category. *Id.* Based on all of these factors, EPA concluded that "it is reasonable to forgo quarterly monitoring and choose semiannual monitoring as the [best system of emission reduction] for compressor stations." *Id.*; *see generally id.* at 57,412-18, 57,420-21 & Table 5, & 57,427-29.

EPA exercised permissible policy judgment in deciding how to consider costs for purposes of selecting the appropriate monitoring interval for compressor stations. Section 7411 requires that EPA "take[] into account the cost of achieving such [emission] reduction," along with other identified factors, in determining standards, 42 U.S.C. § 7411(a)(1), but "does not set forth the weight that should be assigned" to each factor. *Lignite Energy Council v. EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999). Accordingly, "[EPA] is free to exercise [its] discretion in this area," and the Court "must therefore uphold EPA's decision [determining Section 7411 requirements] if such action is supported on either air or nonair (including economic) grounds." *New York v. Reilly*, 969 F.2d 1147, 1150 (D.C. Cir. 1992). Here, EPA's consideration of costs fell well within the boundaries of its reasonable exercise of policy discretion.

Petitioners' criticisms again fail to demonstrate that they are likely to prevail on the merits. Petitioners' wrongly portray EPA's analysis of incremental cost as a "new metric" and a departure from "past practice." Motion at 11-12. In fact, EPA has commonly considered incremental cost when determining Section 7411(b) requirements, including monitoring requirements. *See, e.g.*, 72 Fed. Reg. at 64,864 (considering the incremental cost-effectiveness of more stringent VOC leak monitoring and valve repair requirements to determine standards for synthetic organic chemical manufacturers); 77 Fed. Reg. 56,422, 56,443 (Sept. 12, 2012) (considering "incremental costs and emissions reductions" to determine requirements for petroleum refineries).

Petitioners also decry EPA's consideration of economic hardship and of potential efficiencies and cost savings from applying the same monitoring frequency for well sites and compressor stations. *See* 85 Fed. Reg. at 57,421 n.59 (citing economic literature reflecting the significant financial hardship the Covid-19 pandemic is placing on the industry); *id.* at 85,421 n.60 (citing public comments from facilities with both well sites and gathering and boosting compressor stations on potential efficiencies and savings from synchronous monitoring). But EPA did not err in taking these secondary cost considerations into account. They were pertinent and informed EPA's decision on where to strike the appropriate policy balance. Moreover, EPA did not describe either of these factors as singularly determinative. Rather, these factors "influence[d] [EPA's] evaluation of the appropriateness of selecting quarterly monitoring as compared to semiannual monitoring," the latter of which EPA had independently found to be the more cost-effective option regardless. *Id.* at 85,421; *accord* 80 Fed. Reg. at 56,624 (considering cost savings as part of the analysis for the proposed 2016 Rule).

II. Petitioners have not demonstrated irreparable harm.

A stay is not to be granted unless petitioners can show they will suffer irreparable harm of "such imminence that there is a clear and present need for equitable relief. *Wisconsin Gas Co.*, 758 F.2d at 674 (internal quotation marks omitted). Such harm must be "both certain and great" to justify the extraordinary relief of a stay pending review. *Id.* Petitioners fail to meet this stringent burden.

Petitioners assert that their members will be harmed by foregone emission reductions that they argue would otherwise be achieved if sources continue to implement the 2016 Rule's requirements for low production wells and compressor stations. Petitioners assert that this injury will occur from a combination of increased VOC, methane, and hazardous air pollutant emissions. Petitioners do not base their irreparable harm argument on EPA's Regulatory Impact Analysis. Instead, Petitioners estimate much *higher* foregone emission reductions and argue that these higher quantities will cause irreparable harm. For example, Petitioners estimate over 21,000 metric tons of additional VOC emissions, 77,000 metric tons of additional methane and 800 metric tons of additional hazardous air pollutants in 2021. Motion at 24, 25, A0078 (Table 2) & A0088 (Table 5)[4]; Austin Decl. ¶¶ 23-24. Petitioners' estimates are unreliable, however, due to assumptions that likely over-state the alleged impacts.

First, Petitioners rely on facility-level downwind measurement-based studies to estimate emissions factors for fugitive emissions at low production well sites. Austin Decl. ¶¶ 25-26. But such studies are not appropriate for evaluating fugitive emissions for reasons EPA explained in the rulemaking. *Id.* ¶ 26 & nn.7-8 (citing Responses). Petitioners simply assume, without foundation, that 50 percent of all site-level emissions are attributable to fugitive emissions. Motion at A0087. However, "neither industry, nor the EPA was able to reproduce this estimate." Responses at 8-30.

Second, Petitioners increase their estimate of foregone methane emission reductions by including an estimate of "abnormal process conditions" from Zavala-

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[4] Table 2 shows foregone emission reductions Petitioners attribute to compressor station fugitive monitoring requirements, and Table 5 shows what they attribute to low production well requirements. These estimates are added together here.

Araiza et al. Austin Decl. ¶ 27 & n.9. According to Petitioners, these include malfunctions and other issues that lead to high emission rates. Stay Motion at A0090. However, the inclusion of this value may overstate foregone emissions reductions because it is not possible to confirm whether the "abnormal process conditions" detected in Zavala-Araiza et al. were occurring at emission sources that would be regulated under the 2016 Rule (*e.g.*, equipment leaks), or instead are from other onsite activities that do not have 2016 Rule requirements (such as certain types of venting). Austin Decl. ¶ 27.

In contrast, EPA's analysis considered representative sources under normal operating conditions. *Id.* ¶ 28. Specifically, EPA assessed emissions at the component-level, which EPA determined to be the best method to accurately quantify emissions attributable to specific equipment, components, or processes associated with low production well sites and compressor stations. *Id.* While some actual sites may be smaller or larger than the "model plants" or have fewer or greater emissions, EPA's estimates are expected to be representative of sites nationwide. *Id.*

Even the above methodological distinctions cannot fully explain the disparity between Petitioners' much higher estimates and EPA's estimates. For example, Petitioners' estimates of foregone VOC, methane and hazardous air pollutant emission reductions in 2021 (21,100, 77,000 and 810 metric tons, respectively) are more than four times as high as EPA's (approximately 4,700, 17,200 and 180 metric tons, respectively). *See* Regulatory Impact Analysis at 3-29 (Table 3-6)[5]; Austin Decl. ¶ 19. The Court should defer to EPA's reasonable projections. *See U.S. Air Tour Ass'n v. FAA*, 298 F.3d 997, 1008 (D.C. Cir. 2002), *citing Small Refiner*, 705 F.2d at 535.

Petitioners also fail to put any estimates of foregone emission reductions into context. For example, the foregone emission reductions EPA estimated in its Regulatory Impact Analysis are only equivalent to 0.066% (*i.e.*, less than one tenth of one percent) of the methane emissions reported in the U.S. Greenhouse Gas Inventory for 2018, and 0.006% (*i.e.*, less than one hundredth of one percent) of the total U.S. greenhouse gas emissions for that year. Austin Decl. ¶ 29. Even if Petitioners' questionably high estimates were accurate, those are only equivalent to less than a third of one percent of 2018 U.S. methane emissions and less than a thirtieth of one percent of total 2018 U.S. greenhouse gas emissions. Id. ¶ 30.

Similarly, the foregone emission reductions EPA estimates are minute in comparison to the total emissions EPA projects from the U.S. oil and gas sector. As shown in the Austin Declaration, these foregone emission reductions are equivalent to only 0.19% (less than a fifth of one percent) of the VOC emissions

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[5] EPA's estimates, reported in short tons, are converted here to metric tons (rounding VOC and methane to the nearest 100 and hazardous air pollutants to the nearest 10) for ease of comparison. *Id.*

and 0.21% (a little over a fifth of one percent) of the hazardous air pollutant emissions[6] EPA projects from the sector in 2021. *Id.* ¶ 31 & Table 2.

Finally, despite the contrary impression Petitioners attempt to convey, EPA projects a substantial overall reduction of air pollution from implementation of the 2016 Rule as revised in 2020. By 2025, EPA projects that such implementation will achieve emission reductions of 111,000 to 144,000 metric tons per year of VOCs and 247,000 to 292,000 metric tons per year of methane. *Id.* ¶ 32.

It was Petitioners' burden to prove that without a stay they will incur irreparable harm during the litigation that will be both certain and great. They did not do so.

III. The concrete harm to the public interest outweighs Petitioners' speculative alleged harm.

Petitioners' narrow interests in securing limited additional emissions reductions while this case is pending are outweighed by the concrete benefits to the public interest furthered by the Technical Rule. As enshrined in the CAA, the United States has a concomitant interest in "economic growth . . . consistent with the preservation of existing clean air resources." 42 U.S.C. § 7470(3). The rule provisions at issue will save the oil and gas industry approximately $27 million in

[6] Hazardous air pollutants are regulated under a different statutory program, 42 U.S.C. § 7412, and EPA's separate standards issued under that program are not under review here. The 2016 Rule did incidentally reduce hazardous air pollutants, but that was never its purpose or main effect.

avoided compliance costs, and the public will still enjoy the vast majority of emissions reductions from new sources. Austin Decl. ¶ 34. These cost savings are exactly the type of economic impacts that Congress anticipated EPA would address under the CAA. Petitioners have not shown that this Court should intervene to sacrifice economic growth when the public is better served by the Technical Rule.

CONCLUSION

For the foregoing reasons, Petitioners' motion should be denied.

Dated: December 11, 2020.

Respectfully submitted,

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CERTIFICATE OF COMPLIANCE

1. This document complies with the applicable type-volume limit, because, excluding the parts of the document exempted by Federal Rule of Appellate Procedure 32(f), this document contains 5,197 words.

2. This document complies with the typeface requirements of Federal Rule of Appellate Procedure 32(a)(5) and the type-style requirements of Federal Rule of Appellate Procedure 32(a)(6) because this document has been prepared in a proportionally spaced typeface using Microsoft Word 2016 in 14-point Times New Roman font.

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Counsel for Respondents

CERTIFICATE OF SERVICE

I hereby certify that on December 11, 2020, I electronically filed the foregoing document with the Clerk of the Court for the United States Court of Appeals for the District of Columbia Circuit using the Appellate Electronic Filing system.

/s/ *Brian H. Lynk*
BRIAN H. LYNK

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NOT YET SCHEDULED FOR ORAL ARGUMENT

No. 20-1360 and consolidated cases

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

ENVIRONMENTAL DEFENSE FUND, et al.,
Petitioners,

v.

ANDREW WHEELER, et al.,
Respondents.

On Petition for Review of Final Agency Action of the
United States Environmental Protection Agency

APPENDIX TO RESPONDENTS' MEMORANDUM IN OPPOSITION TO MOTION FOR PARTIAL STAY PENDING REVIEW

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[1] The final rule preambles for the Technical Rule and the 2016 Rule, respectively, are set forth in the Attachments to Petitioners' Motion for a Partial Stay. *See* Motion at A0001-64 (full copy of 85 Fed. Reg. 57,398 (Sept. 15, 2020)); *id.* at A0219-339 (full copy of 81 Fed. Reg. 35,824 (June 3, 2016)).

UNITED STATES COURT OF APPEALS
FOR THE DISTRICT OF COLUMBIA CIRCUIT

ENVIRONMENTAL DEFENSE FUND et al., Plaintiffs, v. ANDREW R. WHEELER, in his official capacity as Administrator of the United States Environmental Protection Agency, and the UNITED STATES ENVIRONMENTAL PROTECTION AGENCY, Defendants.	No. 20-1360 (and consolidated)

DECLARATION OF ANNE AUSTIN

1. I, Anne Austin (formerly Idsal), under penalty of perjury, affirm and declare that the following statements are true and correct to the best of my knowledge and belief, and are based on my own personal knowledge or on information contained in the records of the United States Environmental Protection Agency ("EPA" or the "Agency") or supplied to me by EPA employees under my supervision.

2. I am Principal Deputy Assistant Administrator for the EPA Office of Air and Radiation ("OAR"), which is located at 1200 Pennsylvania Avenue, NW, Washington, D.C. 20460.

3. OAR is the EPA headquarters-based unit with primary responsibility for administration of the Clean Air Act (CAA). As the Principal Deputy Assistant Administrator for OAR, I serve as the principal advisor to the Administrator of EPA on matters pertaining to air and radiation programs, and I am responsible for managing these programs, including: program

policy development and evaluation; development of emissions standards; program policy guidance and overview; and technical support and evaluation of regional air and radiation program activities.

4. As part of my duties as Principal Deputy Assistant Administrator of OAR, I oversee the development and implementation of regulations, policy, and guidance associated with section 111 of the Clean Air Act (CAA), 42 U.S.C. § 7411.

5. This declaration is filed in support of the EPA's Response to Motion for Partial Stay Pending Review in *Environmental Defense Fund et. al. v. Wheeler*, No. 20-1360 (and consolidated cases) (D.C. Cir.).

6. Section 111(b) of the CAA, 42 U.S.C. § 7411(b), requires that EPA establish "standards of performance" for new sources in the source categories listed pursuant to that section. These standards are commonly referred to as "new source performance standards" or "NSPS."

7. On August 16, 2012, EPA promulgated an NSPS for the production and processing segments as well as the transmission and storage segment of the crude oil and natural gas source category. The NSPS established standards of performance for reducing volatile organic compound (VOC) emissions from new sources in the production and processing segments as well as the transmission and storage segment of the industry. 77 Fed. Reg. 49,490 (August 16, 2012) ("2012 NSPS").

8. On May 12, 2016, EPA promulgated another NSPS for the production and processing segments as well as the transmission and storage segment, building on the 2012 NSPS. This NSPS established standards of performance for reducing greenhouse gases in the form of limitations on methane from the production and processing segments as well as the

transmission and storage segment of the industry, and limitations on VOC emissions from certain sources in all three segments of the industry that were not previously regulated under the 2012 NSPS. 81 Fed. Reg. 35,824 (June 3, 2016) ("2016 NSPS").

9. On September 14, 2020, EPA published a rule that amends both the 2012 and 2016 NSPS. These amendments remove the transmission and storage segment from the oil and natural source category and rescind the methane and VOC standards of performance for that segment. These amendments also rescinded the methane standards of performance for the production and processing segments. 85 Fed. Reg. 57,018 (Sept. 14, 2020) ("2020 Policy Rule").

10. On September 15, 2020, EPA published the rule at issue in this case, which further amends the 2016 NSPS. These amendments include exempting low production well sites[1] from fugitive emissions monitoring and changing from quarterly to semiannual monitoring for compressor stations in the production segment (commonly referred to as "gathering and boosting compressor stations").[2] 85 Fed. Reg. 57,398 (Sept. 15, 2020) ("2020 Technical Rule"). The record EPA compiled for this rulemaking, including comments from knowledgeable stakeholders and in-depth analyses of the regulatory impacts of this rule, supports the conclusion that these two amendments in the 2020 Technical Rule will not result in near-term irreparable harm.

11. I have relied upon my staff to provide factual information concerning the record and issues in the case for which I make this declaration. The purpose of this declaration is to provide the Court with factual information and context regarding the expected status of controls of fugitive emissions at low production well sites and gathering and boosting compressor stations

[1] A low production well site is a well site with total production at or below 15 barrels of oil equivalent per day. 85 Fed. Reg. 57,398, 57,412.

[2] The amendments at issue do not affect the standards for controlling fugitive emissions ("equipment leaks") in the gas processing segment (i.e., gas processing plants), which are separately regulated in the 2016 NSPS at 40 C.F.R. § 60.5400a.

following promulgation of the 2020 Technical Rule, and to respond to mischaracterizations in the Movants' motion and declarations regarding the anticipated emissions impacts and benefits of these two amendments in the 2020 Technical Rule.

I. Expected Status of Controls Post-2020 Technical Rule

12. The 2016 NSPS required, among other things, semiannual monitoring of all well sites, including low production well sites. The rule also required quarterly monitoring of compressor stations, including gathering and boosting compressor stations. The following paragraphs describe these facilities, the associated control requirements under the 2016 NSPS and the expected status of such control following promulgation of the 2020 Technical Rule.

13. There are several potential sources of fugitive emissions at well sites and compressor stations. 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 release valves (PRVs) or thief hatches on controlled storage vessels that are left open after sampling, can also be the cause of fugitive emissions. Potential sources of fugitive emissions include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines (OELs), pressure relief devices such as pressure release valves, pump seals, valves or improperly controlled liquid storage tanks. Fugitive emissions sources do not include devices that vent as part of normal operations, such as gas-driven pneumatic controllers or gas-driven pneumatic pumps.

14. In order to address fugitive emissions from components at well sites and compressor stations, the 2016 NSPS required an emissions monitoring plan, including specific elements, such as monitoring using optical gas imaging or an instrument that meets the

specifications in EPA Method 21,[3] and procedures and timeframes for identifying and repairing components from which fugitive emissions are detected. The 2016 NSPS required monitoring fugitive emissions components semiannually at well sites and quarterly at compressor stations. Identified sources of fugitive emissions are required to be repaired or replaced to fix detected leaks and resurveyed to verify there are no fugitive emissions. 40 C.F.R. § 60.5397a.

15. As discussed in paragraph 10, the 2020 Technical Rule exempted low production well sites from fugitive emissions monitoring and changed the monitoring frequency for gathering and boosting compressor stations to semiannual monitoring. EPA estimated that in 2021 there would be 18,000 low production well sites and 1,500 gathering and boosting compressor stations subject to the fugitive emissions standards under the 2016 NSPS that would change their monitoring frequency as a result of the 2020 Technical Rule. *Regulatory Impact Analysis for the 2020 Technical Rule* (2020 RIA), Docket No. EPA-HQ-OAR-2017-0483-2295, 3-28, Table 3-4. These estimates exclude those low production well sites and compressor stations that, due to state rule requirements, would not change their monitoring frequency despite the 2020 Technical Rule, as explained below in paragraph 16.

16. Although some well sites would no longer be subject to the monitoring frequencies in the 2016 NSPS, operators of many well sites and compressor stations routinely check for leaks and repair them when found as a result of state rules, voluntary programs, and corporate policies. Further, some states require the same or more frequent monitoring than the 2016 NSPS. For example, California requires weekly audio-visual inspections and quarterly fugitives emissions monitoring using EPA Method 21, with a repair and resurvey schedule for well sites and compressor stations. See Cal. Code Regs. tit. 17, § 95665-95677. Like the 2016

[3] 40 C.F.R. Part 60, App. A-7, Meth. 21.

NSPS, California's regulated components, meaning those components that sources are required to monitor, include threaded connections, flanges, meters, open-ended lines, pressure relief devices, 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. California allows use of optical gas imaging cameras as a screening tool prior to using EPA Method 21 for quarterly inspections. The regulations provide that the timeline for repair is dependent on their compliance phase-in period and the instrument reading thresholds observed during monitoring. Repairs are required within 2 to 14 days, depending on the concentration of the leak identified. Critical components and processes must be repaired during the next scheduled shutdown or within 12 months of detecting the leak, whichever is sooner. The regulations also include delay of repair provision for when parts are needed and for when a component is considered critical to the reliability of the public gas system.

17. In addition to California, a number of other states (e.g., Colorado, Ohio, Pennsylvania, and Texas) similarly require fugitive emissions monitoring of well sites and compressor stations at least at the same frequencies as the 2016 NSPS,[4] while others (e.g., Montana, New Mexico, North Dakota, and Wyoming) have some other form of state regulation for monitoring and repair of fugitive emissions components at well sites and/or compressor stations. For example, North Dakota and Wyoming have state-level regulations specifically requiring fugitive emissions monitoring of well sites and compressor stations using optical gas imaging or EPA Method 21. Montana has state-level regulations specifically covering fugitive emissions components at well sites. New Mexico has state-level regulations specifically

[4] See Tables 3, 6, 15, 17, and 20 in the memorandum titled *Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Standards at 40 CFR Part 60, Subpart OOOOa*, EPA Docket ID No. EPA-HQ-OAR-2017-0483-2277.

prohibiting leaks from wells, tanks, containers, pipe or other storage, conduit, or operating equipment.

18. The following table provides an overview of states that have state-level regulations requiring fugitive emissions monitoring at well sites and/or compressor stations.

Table 1 – State Rules on Fugitive Emissions Monitoring

	CA	CO	MT	ND	NM	OH	PA	TX	UT	WY
Source										
Fugitive Emissions at Well Sites	Yes[1]	Yes[1]	Yes	Yes	Yes	Yes[1]	Yes[1]	Yes[1]	Yes[1]	Yes[1, 2]
Fugitive Emissions at Compressor Stations	Yes[1]	Yes[1]	No	No	No	Yes[1]	Yes[1]	Yes[1]	No	Yes[1, 2]

[1] Fugitive emissions monitoring frequencies are equivalent to those required by the 2016 NSPS.
[2] Wyoming regulations only apply to Upper Green River Basin.

II. Emissions Impacts and Benefits of 2020 Technical Rule

19. **EPA's Estimates of Forgone Emission Reductions:** EPA projected that the amendments to the monitoring frequencies in the 2020 Technical Rule would forgo reductions of 19,000 short tons of methane, 5,200 short tons of VOC, and 200 short tons of HAP in 2021. 2020 RIA, 3-29, Table 3-6. A short ton is equivalent to about 0.91 metric tons. A metric ton is equivalent to 1000 kilograms, or approximately 2,204 pounds.

20. In EPA's estimates in the 2020 RIA of forgone emissions reductions (described in the previous paragraph) and the associated compliance cost reductions (described below in paragraph 34), EPA accounted for the number of low production well sites and gathering and boosting compressor stations that would have implemented controls under the 2016 NSPS between 2016 to 2020 and would continue to do so after promulgation of the 2020 Technical Rule as a result of state requirements. EPA also projected the number of low production well

sites and gathering and boosting compressor stations that would have reduced control obligations due to the 2020 Technical Rule as compared to the 2016 NSPS requirements.

21. In the 2020 RIA, EPA followed two main steps in estimating forgone emissions reductions and compliance cost reductions due to the 2020 Technical Rule. For the first step, EPA developed representative or model facilities for a range of well sites (including a model facility for low production well sites) and gathering and boosting compressor stations. The characteristics of a model facility included typical equipment, operating characteristics, control options, and representative factors including baseline emissions control costs, emissions reductions, and product recovery resulting from each control option. This source-level cost and emission information can be found in the *Background Technical Support Document for the Final Reconsideration of the New Source Performance Standards*, 40 CFR Part 60, subpart OOOOa, Docket No. EPA-HQ-OAR-2017-0483-2290.

22. For the second step, the number of incrementally affected facilities for each type of equipment or facility were estimated. An incrementally affected facility is a facility for which EPA would expect a change in the adoption of emission controls as a result of a regulatory or deregulatory action, incurring a change in emissions or compliance costs. Changes in national-level emissions and cost estimates are calculated by multiplying the modeled source-level estimates from the first step of its analysis, described above in paragraph 21, by the number of incrementally affected facilities in each projection year from the second step of its analysis. In addition to emissions reductions, some control options result in natural gas recovery, which can then be combusted in production or sold. The estimates of national cost reductions include the values of the forgone product recovery where applicable.

23. **Petitioners' Estimates of Forgone Reductions:** By contrast, Environmental Petitioners claim that the amendments to the monitoring frequencies in the 2020 Technical Rule will cause, in 2021 alone, the increase of more than 77,000 metric tons of methane, 21,000 metric tons of VOCs, and 800 metric tons of HAPs (i.e., 84,615 short tons of methane, 23,077 short tons of VOCs and 879 short tons of HAP). Brief at 22. These estimates are about four times EPA's estimates described above in paragraph 19.

24. Environmental Petitioners rely on Environmental Defense Fund's (EDF) estimates of increased emissions, A0078,[5] Tbl. 2 (estimates for gathering and boosting compressor station) and A0088, Tbl. 5 (estimates for low production well sites).

25. The EDF estimates use different assumptions and inputs from those in the 2020 RIA. These estimates in EDF's analysis are based on the same studies that EDF discussed in its comments on the proposal for the 2020 Technical Rule.[6] As explained in its response to these comments and summarized below in paragraphs 26 and 27, EDF's analysis contains certain assumptions and inputs that could overestimate the foregone emissions.

26. First, EDF's analysis relies on the use of facility-level downwind measurement-based studies to estimate emissions factors for fugitive emissions at low production well sites. As EPA explained in its response to these comments, it is not appropriate to rely on the use of remote measurements that include emissions from all sources at the site, including permitted emissions. Downwind total site emissions studies are not appropriate when evaluating fugitive emissions because these studies include allowable or unregulated emissions from sources located on these same sites. Where component-level fugitive emissions are not quantified, it is not

[5] "A" cites refer to Petitioners' consecutively-paginated attachments submitted with their motion.
[6] See EPA Docket ID No. EPA-HQ-OAR-2017-0483-2041.

possible to differentiate those allowable or unregulated emissions from fugitive emissions.[7] Further, EDF assumes that 50 percent of the site-level emissions are attributed to fugitive emissions. Brief at A0087. As EPA noted in response to a comment on this assumption, "neither industry, nor the EPA was able to reproduce this estimate."[8]

27. EDF's analysis also differs from EPA's by increasing the estimate of methane by including an estimate of abnormal process conditions from Zavala-Araiza et al.[9] "Abnormal process conditions," according to EDF, includes malfunctions and other issues that lead to high emission rates. A0090. The Environmental Petitioners conclude without explanation that these emissions would have been decreased by use of leak detection and repair. A0091. However, the inclusion of this value may actually overstate emissions reductions because emissions from these "abnormal process conditions," which refer to malfunctions such as failures of tank control systems or malfunctions of separator dump valve, are not fugitive emissions covered by the 2016 NSPS.[10]

28. By contrast, EPA's analysis looked at representative sources under normal operating conditions. Specifically, for low production well sites and gathering and boosting compressor stations, model facilities were developed based on average component-level counts and emission factors to estimate representative baseline fugitive emissions of methane, VOC, and HAP. These emissions reflect normal operating conditions and do not account for "abnormal

[7] See *EPA Responses to Public Comments on the Reconsideration of New Source Performance Standards (NSPS) Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed, and Modified Sources Reconsideration 40 CFR Part 60, Subpart* OOOOa, Docket ID No. EPA-HQ-OAR-2017-0483-2291, 8-23 and 8-29 (Section 8.1.1.8 Emission Factors/Baseline Emissions: 3rd and 4th Response to Comment); and 8-84 (Section 8.1.2.6 EDF Studies: 2nd response to comment).
[8] *Id*, 8-30.
[9] Zavala-Araiza, D., et al. *Super-emitters in natural gas infrastructure are caused by abnormal process conditions*. Nature Communications Volume 8, 14012 (2017).
[10] See *EPA Responses to Public Comments on the Reconsideration of New Source Performance Standards (NSPS) Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed, and Modified Sources Reconsideration 40 CFR Part 60, Subpart* OOOOa, Docket ID No. EPA-HQ-OAR-2017-0483-2291, 8-46.

process conditions" which, as explained in paragraph 27 above, are the result of a malfunction and not typical emissions from low production well sites or gathering and boosting compressor stations. Assessing emissions at the component-level is the most appropriate method to accurately quantify emissions as counts and emissions are attributed to specific equipment, components, or processes associated with low production well sites and gathering and boosting compressor stations and subject to fugitive emissions monitoring under the 2016 NSPS. Using average component-counts and emission factors for quantifying these emissions is the best method the EPA has developed and reflects the best available information regarding source operations. It is possible that some actual sites may be smaller or larger than the model plants or have smaller or larger emissions per facility than estimated, but on average, the estimates developed by the EPA are expected to be representative of low production well sites and gathering and boosting stations nationwide. This model plant approach is consistent with the approach used for the 2016 NSPS.

29. As discussed in paragraph 19 above, the 2020 RIA projected that the forgone methane emission reductions in 2021 from fugitive emissions at low production well sites and gathering and boosting compressor stations would be about 19,000 short tons of methane (about 17,000 metric tons) or about 430,000 metric tons CO_2-equivalent (CO_2e) using a global warming potential of 25. While EPA is not aware of projections of U.S. and global emissions of greenhouse gas emissions in 2021, to give a sense of the magnitude of the forgone methane emissions reductions under the 2020 Technical Rule, the projected forgone reductions are equivalent to:

a. 0.066%, or less than one tenth of one percent of the total methane emissions reported in the U.S. GHG Inventory for 2018[11] (650 million metric tons (MMT) CO_2e, using a global warming potential of 25);

b. 0.006%, or less than one-one hundredth of one percent of the total GHG emissions in the U.S. GHG Inventory for 2018 (6,677 MMT CO_2e);

c. 0.005%, or less than one-one hundredth of one percent of the total global methane emissions as reported in the World Resources Institute (WRI) CAIT Climate Data Explorer for 2016[12] (8,110 MMT CO_2e, using a global warming potential of 25); and

d. 0.001%, or about one-one thousandth of a percent of the total global GHG emissions as reported in the WRI CAIT Climate Data Explorer in 2016 (46,100 MMT CO_2e).

30. As discussed above, EPA disagrees with Environmental Petitioners' estimates of forgone methane emissions (77,000 metric tons[13] in 2021, or 1.9 million metric tons CO_2e using a global warming potential of 25). However, even based on Petitioners' over-estimates, as shown below, the fraction of total emissions their estimates represent would also be small, similar to the magnitude of EPA's estimates as described in the prior paragraph:

a. 0.296%, or less than one percent of the total methane emissions reported in the U.S. GHG Inventory for 2018 (650 million metric tons (MMT) CO_2e, using a global warming potential of 25);

[11] U.S. Environmental Protection Agency (U.S. EPA). 2020. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2018. EPA/430-R-20-002. April. Available at https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks-1990-2018

[12] Available at https://cait.wri.org/historical/Country%20GHG%20Emissions

[13] Petitioner's brief at 3.

b. 0.029%, or less than one-tenth of one percent of the total GHG emissions in the U.S. GHG Inventory for 2018 (6,677 MMT CO_2e);

c. 0.024%, or less than one-tenth of one percent of the total global methane emissions as reported in the World Resources Institute (WRI) CAIT Climate Data Explorer for 2016 (8,110 MMT CO_2e, using a global warming potential of 25); and

d. 0.004%, or less than one-one hundredth of one percent of the total global GHG emissions as reported in the WRI CAIT Climate Data Explorer in 2016 (46,100 MMT CO_2e).

31. Similarly, compared to the overall VOC and HAP emissions from the oil and natural gas sector, the forgone VOC and HAP reductions in 2021 due to the changes to monitoring frequencies in the 2020 Technical Rule are also relatively small. For this comparison, EPA compared the estimates in the 2020 RIA for these forgone VOC and HAP reductions in 2021 to the overall VOC and HAP emissions from the oil and natural gas sector as presented in the most recent EPA National Emissions Inventory (NEI)[14] and reproduced in Table 2 below (i.e., 5,200 short tons compared to 2.7 million short tons of VOC, respectively and 200 short tons compared to 97 thousand short tons of HAP). The projected foregone emission reductions in 2021 are equivalent to 0.19% (less than a fifth of one percent) of the VOC emissions and 0.21% (a little over a fifth of one percent) of the projected hazardous air pollutant emissions from the sector. The VOC estimates in the NEI, which were presented in kilotons (kt), or thousand metric

[14] 2017 NEI (published 2020). Available at https://www.epa.gov/air-emissions-inventories/2017-national-emissions-inventory-nei-data.

tons, are converted here to short tons for comparison with the forgone VOC emissions reductions presented in the 2020 RIA. Note, totals may not sum due to rounding.

TABLE 2. U.S. VOC AND HAP EMISSIONS FROM NATURAL GAS AND PETROLEUM SYSTEMS (2017)

Sector	VOC (kt)	VOC (short tons)	HAP (short tons)
Oil and Natural Gas Production and Natural Gas Processing and Transmission (Total)	**2,504**	**2,760,000**	**97,000**
Oil and Natural Gas Production	2,478	2,732,000	94,000
Natural Gas Processing	12	13,000	3,000
Natural Gas Transmission and Storage	14	15,000	1,000

Note: Emissions from the 2017 NEI (released April 2020).

32. Further, EPA's analysis shows that, even with the changes due to the 2020 Technical Rule, the amended 2016 NSPS will still achieve substantial emissions reductions. EPA performed this analysis in response to public comments on the proposal for the 2020 Technical Rule. In this analysis, EPA developed a pair of rough estimates of the ongoing effects of the 2016 NSPS requirements that remain in place after promulgation of the 2020 Policy Rule and as amended by the 2020 Technical Rule. The estimates were developed for new sources in the production and processing segments for the projected year of 2025. EPA projected that by 2025, the amended 2016 NSPS requirements would produce 272,000 to 322,000 short tons (or 247,000 to 292,000 metric tons) of methane reductions and 122,000 to 159,000 short tons (or 111,000 to 144,000 metric tons) of VOC emissions reductions. The information, assumptions, and analysis supporting these projections are presented in Section 14.1 of the Response to Public Comment, Docket No.EPA-HQ-OAR-2017-0483-2291.

33. **Avoided Compliance Costs for Entire Rule from 2021 to 2030:** EPA assessed avoided compliances costs to the industry as a result of the 2020 Technical Rule. Table 3-18 of the 2020 RIA shows the discounted stream of cost reductions discounted to 2020 using a 7 percent discount rate. 2020 RIA, Docket No. EPA-HQ-OAR-2017-0483-2295. The present value of total compliance cost reductions is $750 million, with an equivalent annualized value of $100 million per year. The present value of the stream of cost reductions discounted to 2020 using a 3 percent discount rate is $950 million, with an equivalent annualized value of $110 million per year. Dollar estimates are denominated in 2016 dollars.

34. **Avoided Compliance Costs in 2021 Due to Changes in Fugitives Monitoring Frequency Requirements:** Using the same analysis presented in the 2020 RIA, EPA estimates that changes to fugitives monitoring frequency requirements at low production well sites (from semiannual to no monitoring) and gathering and boosting compressor stations (from quarterly to semiannual) alone will result in $27 million in compliance cost reductions. This information can be deduced from Table 3-10 of the 2020 RIA by comparing annualized cost reductions (including foregone revenue) in 2021 for Option 3 to Option 1. Option 3 assesses the cumulative impacts of changes to recordkeeping and reporting for the fugitive emissions requirements as well as changes to the fugitives monitoring frequency requirements, while Option 1 assesses the impacts of changes to recordkeeping and reporting requirements only. Taking the difference in cost reductions between the two options isolates the impact of the changes to fugitives monitoring frequency requirements.

35. **Conclusion:** Based on a full assessment of the information available to me and the record EPA compiled for this rulemaking, including comments from knowledgeable stakeholders and in-depth analyses of the regulatory impacts of this rule, I support the conclusion

that the changes to the fugitive emissions monitoring frequencies in the 2020 Technical Rule will not result in near-term irreparable harm.

I declare under penalty of perjury that the foregoing is true and correct.

Executed this 11th day of December, 2020.

Anne L. Austin
Principal Deputy Assistant Administrator
Office of Air and Radiation
United States Environmental Protection Agency

United States Environmental Protection Agency

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

Background Technical Support Document for the
Final Reconsideration of the New Source Performance Standards
40 CFR Part 60, subpart OOOOa

August 2020

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ACRONYMS AND ABBREVIATIONS

Acronyms/Abbreviations	Description
API	American Petroleum Institute
BMPs	Best Management Practices
boe	Barrels of Oil Equivalent
BSER	Best System of Emission Reduction
CAC	Criteria Air Contaminant
CAPP	Canadian Association of Petroleum Producers
CDPHE	Colorado Department of Public Health and Environment
CEDRI	Compliance and Emissions Data Reporting Interface
CFR	Code of Federal Regulations
EHS	Environmental Health and Safety
EPA	Environmental Protection Agency
FEAST	Fugitive Emissions Abatement Simulation Toolkit
GHG	Greenhouse Gases
GHGRP	Greenhouse Gas Reporting Program
GOR	Gas to Oil Ratio
H_2S	Hydrogen Sulphide
Hr	Hour
Kg	Kilograms
Lb/yr	Pound per Year
LDAR	Leak Detection and Repair
Mcf	Thousand Cubic Feet
Mscf	Million Standard Cubic Feet
NMOC	Non-methane Organic Compound
NO_x	Nitrogen Oxides
NSPS	New Source Performance Standards
OEL	Open-Ended Line
OGI	Optical Gas Imaging
PE	Professional Engineer
PRV	Pressure Relief Valve
ppm	Parts per Million
RIA	Regultory Impacts Analysis
QA/QC	Quality Assurance/Quality Control
Scf	Standard Cubic Feet
Scfh	Standard Cubic Feet per Hour
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

1.0 INTRODUCTION

This background technical support document (TSD) provides information relevant to the final amendments of the Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources ("NSPS OOOOa"). This TSD provides the unit-level analysis supporting the determination of the best system of emission reduction (BSER) related to the collection of fugitive emissions components located at well sites and at compressor stations.

The amendments update the BSER analysis for fugitive emissions requirements at well sites and compressor stations. Previous BSER analyses for other affected facilities are not updated here and are available in documents outlined in Section 1.1. Chapter 2 presents detailed information and analyses pertaining to these amendments, including emission data and discussions of available control options and the costs that were considered in the development of standards reflecting the BSER for these emission sources.

1.1 Supporting Documentation

This action follows the development of several prior oil and gas new source performance standards (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 (GHG Inventory), 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. The most recent available GHG Inventory covers data from 1990-2016 and currently

[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.

available GHGRP data cover 2011-2016. These new emissions and activity data have been reviewed for the proposed reconsideration and incorporated into this analysis. For the purposes of this document these data sources are referred to as "GHG Inventory" and "GHGRP."

- 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, published in June, 2016, will be referred to in this document as "2016 NSPS Final TSD".[5]
- The TSD for the 2018 proposed reconsideration of the NSPS, published in October, 2018, will be referred to in this document as "2018 NSPS Proposal TSD".[6]

All of the calculations supporting the analyses in this document in the form of spreadsheets are available from the docket for this rulemaking as attachments to this document.

[4] Docket ID No. EPA-HQ-OAR-2010-0505-5021.
[5] Docket ID No. EPA-HQ-OAR-2010-0505-7631.
[6] Docket ID No. EPA-HQ-OAR-2017-0483-0040.

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,[7] 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 crude oil and natural gas production 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 (*e.g.,* an intermittent pneumatic controller that is venting continuously).

As discussed in Section 2.2, NSPS OOOOa includes standards for fugitive emissions components at well sites and compressor stations in addition to the previously promulgated equipment leak standards for onshore natural gas processing plants.[8] In order to differentiate which components and equipment

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[7] As described in Section 2.3.1 of the TSD, model plants are the best method that EPA has developed so far to represent equipment and component counts at the different site types, while also allowing for consideration of costs and emission reduction impacts. While actual sites may be larger than the models, focus was placed on small sites since that is where the impacts are most likely to be more burdensome. Where impacts on society are reasonable for small sites, most likely the impacts on society will be reasonable for larger sites or sites with larger quantities of emissions.

[8] 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.

were subject to these standards, NSPS OOOOa includes a separate definition for "fugitive emissions component." Specifically, NSPS OOOOa defines fugitive emissions component as follows. This definition includes slight changes made in the final amendments.

> *Fugitive emissions component means any component that has the potential to emit fugitive emissions of VOC at a well site or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to §§60.5411 or 60.5411a, thief hatches or other openings on a controlled storage vessel not subject to §§60.5395 or 60.5395a, compressors, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the device's vent, such as the thief hatch on a controlled storage vessel, would be considered fugitive emissions.*

2.2 Fugitive Emissions Requirements in 2016 NSPS OOOOa

On June 3, 2016, the U.S. Environmental Protection Agency (EPA) promulgated fugitive emissions standards for the collection of fugitive emissions components located at well sites and compressor stations at 40 Code of Federal Regulations (CFR) part 60, subpart OOOOa (2016 NSPS OOOOa).[9] 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 were 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 were required to perform monitoring using optical gas imaging (OGI), where any visible image is defined as a fugitive emission that 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") was allowed to identify fugitive emissions, where an instrument reading of 500 parts per million (ppm) or greater was considered a fugitive emission. Each owner or operator was required to develop and implement a fugitive emissions monitoring plan that included site-specific information, such as a site map and observation path which ensures line of sight for each fugitive emissions component during the monitoring survey, in addition to specifying how the survey was conducted (*i.e.,* which monitoring instrument is used, how operator-specified parameters such as viewing distance are established, and other parameters as defined in the 2016 NSPS OOOOa).

[9] 81 FR 35824.

In March 2018, the EPA amended the fugitive emissions standards by removing the requirement that repairs which have been delayed beyond the 30-day repair 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 Alaska North Slope.

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. Model plants were developed to analyze potential options for the control of fugitive emissions at well sites and compressor stations.

The primary data sources used to develop the model plants include the DrillingInfo HPDI® database,[10] the 1996 EPA/GRI Study,[11] EPA's GHG Inventory for 2017, and EPA's GHG Mandatory Reporting Rule (40 CFR part 98, subpart W). In some cases the model plants were supplemented or adjusted based on information received in public comments.

The following sections describe the four types of model plants developed and used to evaluate impacts for these amendments to NSPS OOOOa. Specifically, these types are (1) well sites, (2) 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 (also referred to as "low production" well sites), (3) wellhead only sites, and (4) compressor stations. These model plants are discussed in Sections 2.3.2, 2.3.3. 2.3.4, and 2.3.5, respectively. For each type of model plant, the processes that are represented by the model plant are discussed, along with the basics of how the model plant was developed. Fugitive model plants were originally developed for the 2015 NSPS OOOOa proposed rule and have evolved since that time in response to new information and public comments. More information on the history of this model plant development can be found in the 2015 NSPS Proposal TSD, the 2016 NSPS Final TSD, and the 2018 NSPS Proposal TSD. Any changes to the model plants since the 2018 NSPS Proposal TSD are discussed in the following sections, and the parameters of the 2020 Final NSPS model plants presented here.

Following presentation of Sections 2.3.2 through 2.3.5 which provide the model plant characteristics, Section 2.3.6 explains the calculation of baseline emissions for each model plant.

[10] Drilling Information, Inc. 2014. *DI Desktop.* 2014 Production Information Database.
[11] 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).

2.3.2 Well Site Model Plants

Oil and natural gas production practices and equipment vary from well site to well site. A well site can serve one well or multiple wells. 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 with a number of operations such as production, extraction, recovery, lifting, stabilization, separation and/or treating of petroleum and/or natural gas (including condensate). The equipment to perform these operations (including piping and associated components, compressors, generators, separators, storage vessels, and other equipment) has components that may be sources of fugitive emissions. Therefore, the number of components with the potential for fugitive emissions can vary depending on the number of wells and the number of major production and processing equipment at the site.

Another factor that impacts the operations at a well site, and the resulting fugitive emissions potential, is the nature of the oil and natural gas being extracted. This can range from well sites that only extract and handle "dry" natural gas to those that extract and handle heavy oil. In order to characterize the differences in type of oil/natural gas being extracted, 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 standard cubic feet (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"). Note that separate model plants were developed for low production well sites and the model plants discussed in this section represent well sites with production above the low production level (*i.e.,* 15 boe per day). The low production model plants are discussed below in Section 2.3.3.

Model plants were developed to provide a representation of well sites to characterize sites across the spectrum of well sites. The basic approach used was to assign a number of specific equipment types for each well site model plant and then to estimate the number of components based on assigned numbers of components per equipment type. For each well site model plant, we included two wells, which was based on data from the DrillingInfo HPDI® database. The specific types of equipment assigned to the model plants were wellheads, separators, meters/piping, in-line heaters, dehydrators, and storage vessels. In previous analyses, the GRI data was used to estimate the number of each type of equipment per gas well sites. However, for purposes of the 2020 Final NSPS, for all equipment types except storage vessels, the reported equipment counts for each well site subtype in the 2017 GHG Inventory were used to determine the average major equipment counts per well. The types of fugitive emissions components associated with these production equipment types include: valves, connectors, OELs, and PRVs.[12] Component counts for each type of 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. It was assumed that each well site has one storage vessel subject to fugitive emissions requirements and that each storage vessel contains one thief hatch or PRV with the potential for fugitive emissions.

More details on the development of these model plants prior to the 2018 NSPS OOOOa proposal is provided in Section 2.3.2 of the 2018 NSPS Proposal TSD.[13] No comments were received on the 2018 NSPS OOOOa proposal that resulted in a change in the model plants for well sites exceeding 15 boe per day averaged over the first 30 days of production. However, following proposal we did update the analysis using the activity counts in the 2017 GHG Inventory. While the activity factors by equipment type changed slightly, once rounded to the nearest integer, there was no change in the major equipment counts from proposal. While there were comments regarding the number of storage vessels that would be subject to the fugitive requirements for the model plant,[14] evaluation of those comments did not result in a change. The major equipment and fugitive emissions component counts for the well site model plants are presented in Table 2-1.

[12] It is important to note that the model plants only estimate emissions from a portion of the components that are included in the fugitive emissions program. For example, the model plants estimate emissions from valves, connectors, OELs, and PRVs, but do not estimate emissions from compressors, instruments, and meters.
[13] See Docket ID No. EPA-HQ-OAR-2017-0483-0040.
[14] See the 2020 Response to Comment Document, Section 8.1 located at Docket ID No. EPA-HQ-OAR-2017-0483.

Table 2-1. Production Equipment and Component Counts for Well Site Model Plants

Production Equipment	Model Plant Equipment Counts	Component Count Per Model Plant[a]				
		Valves	Connectors	OELs	PRVs	Thief Hatches
Natural Gas Well Site Model Plant						
Wellheads	2	19	74	2	0	--
Separators	2	43	137	8	3	--
Meters/Piping	2	26	96	1	1	--
In-Line Heaters	1	14	65	2	1	--
Dehydrators	1	24	90	2	2	--
Storage Vessels	1	--	--	--	--	1
	Rounded Total	127	462	14	7	1
Oil Well Site (<300 GOR) Model Plant						
Wellheads	2	10	8	0	2	--
Separators	1	6	10	0	0	--
Headers	1	5	4	0	0	--
Heater/Treaters	1	8	20	0	0	--
Storage Vessels	1	--	--	--	--	1
	Rounded Total	29	42	0	2	1
Oil with Associated Gas Well Site (>300 GOR) Model Plant						
Wellheads	2	10	8	0	2	--
Separators	1	6	10	0	0	--
Meters/Piping	2	26	96	1	1	--
Headers	1	5	4	0	0	--
Heater/Treaters	1	8	20	0	0	--
Storage Vessels	1	--	--	--	--	1
	Rounded Total	55	138	1	3	1

[a]Since the component counts were calculated and then rounded, the sum of the number of components per production equipment type may not equal the total shown.

During development of the 2018 NSPS OOOOa proposal, the American Petroleum Institute (API) provided information on initial monitoring for fugitive emissions at over 4,000 well sites.[15] This information included counts of the major production equipment (*i.e.,* wellhead, separator, heater/treater, meter/piping, compressor, in-line heater, and dehydrator). In some cases, the information also included the number of storage vessels, engines, generators, vapor recovery units (VRUs), flares, pumps, and pumping units. The information provided also specified if the well site was a single wellpad, or multi wellpad.

[15] EPA-HQ-OAR-2017-0483-0036, Attachment 4.

Therefore, we determined the average number of each major production equipment for single wellpads, multi wellpads, and the overall average of each equipment type. For two of the well sites, actual component counts were provided, while the remaining well sites used the average component counts per equipment factors that we use in the model plant analysis to estimate the number of components (*e.g.*, valves, connectors, etc.) at the site.

In June 2019, a study was published in Elementa that examined fugitive emissions from 67 oil and natural gas well sites and gathering and boosting stations in the western U.S.[16] That study included a count of components and major equipment at 65 of the study sites. Specifically, the number of wellheads, separators, meters/piping, compressors, headers, heater/treaters, dehydrators, in-line heaters, and minor separators were reported. Additionally, the number of valves, connectors, open-ended lines, PRVs and flanges were also presented, by each piece of major equipment at the site.

This additional information is summarized in Tables 2-2 and 2-3 below and is comparable to the equipment counts used in the model plant analysis. Therefore, we did not make any updates to the model plant equipment or component counts as a result of this additional data.

Table 2-2. Comparison of Production Equipment Counts for Gas Wells

Production Equipment	Model Plant Equipment Counts	2018 API Equipment Counts[17]			2019 Pasci Study Equipment Counts[18]
		Single Pad	Multi Pad	Combined	
Wellheads	2	1	4	2	2
Separators	2	2	5	3	4
Meters/Piping	2	1	2	2	3
In-Line Heaters	1	1	1	1	1
Dehydrators	1	1	0	1	1
Storage Vessels	1	Not provided	Not provided	Not provided	Not provided

[16] Pacsi, AP, et al. 2019. Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. Elem Sci Anth, 7: 29. DOI: *https://doi.org/10.1525/elementa.368.*
[17] EPA-HQ-OAR-2017-0483-0036, Attachment 4.
[18] Pacsi, AP, et al. 2019. Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. Elem Sci Anth, 7: 29. DOI: *https://doi.org/10.1525/elementa.368.*

Table 2-3. Comparison of Production Component Counts for Gas Wells

Production Equipment	Model Plant Equipment Counts	2018 API Equipment Counts			2019 Pasci Study Equipment Counts
		Single Pad	Multi Pad	Combined	
Valves	127	Not provided	Not provided	Not provided	117
Flanges	0	Not provided	Not provided	Not provided	86
Connectors	462	Not provided	Not provided	Not provided	583
OELs	14	Not provided	Not provided	Not provided	8
PRVs	7	Not provided	Not provided	Not provided	8
Thief Hatches	1	Not provided	Not provided	Not provided	Not provided
Total Components	**611**	**416**	**1,300**	**1,142**	**802**

2.3.3 Low Production Well Site Model Plants

For the 2018 NSPS OOOOa proposal, we created new model plants for well sites that have low production (which was defined as a well site where the average combined oil and natural gas production is less than 15 boe per day averaged over the first 30 days of production). The types of equipment and fugitive emission components that can be at these low production sites are the same as at the non-low production sites, but it is generally expected that there is less equipment (and thus fewer components) at low production sites.

The basis for the equipment counts for the 2018 gas well low production model plants was a study conducted in the Dallas/Fort Worth area (herein referred to as the "Fort Worth Study").[19] Details about how this Fort Worth Study data was used to develop the gas well low production model plants are provided in Section 2.3.2 of the 2018 NSPS Proposal TSD. For the oil well low production model plants, the component counts were calculated based on scaling factors of the component counts for the low production gas well model plant to the component counts for the non-low production gas well model plant.

There were numerous comments submitted on the 2018 proposed amendments related to the fugitive requirements for low production well sites, including comments related to the model plants. Limited data related to component counts at low production well sites were provided through the comments. While the data provided were not sufficient to directly modify the low production model plants, we did re-examine the Fort Worth Study data as a result of the comments. In this re-examination and resulting analysis, we removed any well site reporting zero production because they did not

[19] "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/*.

necessarily represent a low production well site. This is because the Fort Worth Study only provided production for the day prior to any site visit in the study, and zero production may have been due to any number of reasons not related to the actual normal production at the site (*e.g.,* well shut-in). This resulted in having information on 16 well sites that we assume are low production based on the information provided. We then calculated the average counts of major production and processing equipment reported for the 16 low production well sites and used these average counts as the basis for updating the natural gas well model plant for low production well sites. This resulted in a decrease in the number of separators (from 2 to 1) and meters/piping (from 1 to 0) for the low production gas well pad. Because the fugitive emissions component counts were not available for each individual piece of major production and processing equipment, we continued to use the average fugitive emissions component counts per major production and processing equipment obtained from the 1996 EPA/GRI Study.[20] The result was that the counts decreased for all component types for the low production gas well model plant (except storage vessel thief hatches).

As noted above, the component counts for the two low production oil well model plants were calculated using scaling factors based on the component counts for the low production gas well model plant divided by the component counts for the non-low production gas well model plant. Since the low production gas well model plant component counts decreased, these scaling factors, and thus the components for the low production oil well model plants, decreased. Table 2-4 compares the component counts for the low production model plants for the 2018 NSPS OOOOa proposal with the updated counts for the 2019 NSPS OOOOa final rule.

[20] 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).

Table 2-4. Comparison of Component Count for Low Production Well Site Model Plants

Component Type	2018 Proposal Model Plant	2020 Final Model Plant
Low Production Natural Gas Well Site		
Valves	100	65
Connectors	349	233
OELs	12	8
PRVs	5	4
Thief Hatches	1	1
Low Production Oil Well Site (<300 GOR)		
Valves	23	15
Connectors	32	22
OELs	0	0
PRVs	2	2
Thief Hatches	1	1
Low Production Oil Well with Associated Gas Site (>300 GOR)		
Valves	44	29
Connectors	105	70
OELs	1	1
PRVs	3	2
Thief Hatches	1	1

The major equipment and fugitive emissions component counts for the low production well site model plants are presented in Table 2-5.

Table 2-5. Production Equipment and Component Counts for Low Production Well Site Model Plants

Production Equipment	Model Plant Equipment Counts	Component Count Per Model Plant[a]				
		Valves	Connectors	OELs	PRVs	Thief Hatches
Low Production Natural Gas Well Site Model Plant						
Wellheads	2	19	74	2	0	--
Separators	1	22	69	4	1	--
Meters/Piping	0	0	0	0	0	--
In-Line Heaters	0	0	0	0	1	--
Dehydrators	1	24	90	2	2	--
Storage Vessels	1	--	--	--	--	1
	Rounded Total	65	233	8	4	1
Low Production Oil Well Site (<300 GOR) Model Plant						
Wellheads	2	5	4	0	2	--
Separators	1	3	5	0	0	--
Headers	1	2	2.	0	0	--
Heater/Treaters	1	4	10	0	0	--
Storage Vessels	1	--	--	--	--	1
	Rounded Total	15	22	0	2	1
Low Production Oil with Associated Gas Well Site (>300 GOR) Model Plant						
Wellheads	2	5	4	0	1	--
Separators	1	3	5	0	0	--
Meters/Piping	2	13	4.	1	1	--
Headers	1	4	10	0	0	--
Heater/Treaters	1	3	2	0	0	--
Storage Vessels	1	--	--	--	--	1
	Rounded Total	29	70	1	2	1

[a] Since the component counts were calculated and then rounded, the sum of the number of components per production equipment type may not equal the total shown.

As mentioned above, limited data were also provided by commenters, including counts of wellheads, valves, and storage vessels at low production well sites. A comparison of the counts used in EPA's analysis for NSPS OOOOa final rule to the specific counts information provided by one commenter is presented in Table 2-6. A memorandum with a discussion of that data, in addition to other information and data received in comments related to the development of model plants, including low production model plants, is included in a memorandum provided in Attachment 1 of this TSD.[21]

Table 2-6. Comparison of Low Production Model Plant Methane Emissions

Description	Number of Wellheads	Number of Tanks	Number of Valves	Methane Emissions (tpy)
EPA Final Low Production Gas Well Model Plant	2	1	65	3.5
Gas Well Model Plant Adjusted to IPAA Data	1	1	23	2.5

2.3.4 Wellhead Only Model Plants

As noted earlier in Section 2.3.2, some well sites only consist only of the wellhead. In order to characterize these facilities, we created model plants that consist of wellheads and no major production or processing equipment for each of the three sub-types of well site model plants (*i.e.,* gas well, oil well, and oil with associated gas well sites). For purposes of this analysis, we maintained the assumption of two wellheads per model plant. We did not separate these by 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 2-7. There were no revisions to the wellhead only model plants from the 2018 NSPS OOOOa proposal.

Table 2-7. Equipment and Component Counts for Wellhead Only Well Site Model Plants

Production Equipment	Model Plant Equipment Counts	Average Component Count Per Unit of Model Plant				
		Valves	Connectors	OELs	PRVs	Thief Hatches
Natural Gas Well Site Model Plant						
Wellheads	2	19	75	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

2.3.5 Compressor Station Model Plants

There are three types of compressor stations in the oil and natural gas sector: (1) gathering and boosting stations, (2) transmission stations, and (3) storage stations. The equipment associated with these

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

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 and connectors) that may be sources of fugitive emissions associated with these operations. One model plant was developed for each of the types, which are discussed in the following sections.

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 may 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, based on that information. 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 rule. Compressor seals are discussed in further detail in Chapter 7 of the 2016 Final NSPS OOOOa TSD.

In comments on the 2018 NSPS OOOOa proposal, GPA Midstream (GPA) provided average major production and processing equipment counts for member company gathering and boosting stations.[22] These equipment counts were incorporated into the gathering and boosting model plant and replaced the estimates from the 1996 EPA/GRI study. A comparison of the major production and processing equipment counts estimated using the 1996 EPA/GRI document and the reported counts from GPA are summarized in Table 2-8.

[22] EPA-HQ-OAR-2017-0483-1261.

Table 2-8. Comparison of Major Production and Processing Equipment Counts for Gathering and Boosting Stations

Production Equipment	1996 EPA/GRI Estimate	GPA Reported
Separators	11	5
Meters/Piping	7	6
Gathering Compressors	5	3
In-Line Heaters	7	1
Dehydrators	5	1

A summary of the fugitive emissions component counts based on the GPA reported information for the oil and natural gas gathering and boosting station model plant are presented in Table 2-9.

Table 2-9. Equipment and Component Counts for Gathering and Boosting Station Model Plant

Production Equipment	Model Plant Equipment Counts	Component Count Per Model Plant			
		Valves	Connectors	OELs	PRVs
Gathering and Boosting Stations					
Separators	5	110	340	20	5
Meters/Piping	6	78	288	0	0
Gathering Compressors	3	213	525	9	12
In-Line Heaters	1	14	65	2	1
Dehydrators	1	24	90	2	2
	Rounded Total	**439**	**1,308**	**33**	**20**

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, where the emissions from the open-ended lines are during an active blowdown. As discussed in the 2016 Final NSPS OOOOa TSD, blowdown open-ended lines were excluded from the analysis because these are considered vents and are not sources of fugitive emissions provided there is no leakage past the closed isolation valves when not used for a blowdown. Fugitive emissions component counts were obtained from the 1996 EPA/GRI study. There were no comments received on the 2018 NSPS OOOOa proposal that impacted the natural gas transmission and storage station model plants. A summary of the fugitive emissions component counts is presented in Table 2-10.

Table 2-10. Fugitive Emissions Component Counts for Natural Gas Transmission and Storage Station Model Plants

Component	Model Plant Component Count	
	Transmission Facility	Storage Facility
Valve	673	1,868
Control Valve	31	--
Connectors	3,068	5,571
OELs	51	353
PRVs	14	66
Valve (Injection/Withdrawal)	--	30
Connector (Injection/Withdrawal)	--	89
OELs (Injection/Withdrawal)	--	7
PRVs (Injection/Withdrawal)	--	1

2.3.6 Fugitive Emissions Estimation Method

For the 2018 NSPS OOOOa proposal, baseline model plant emissions were calculated using the model plant fugitive emissions component counts and component-specific oil and natural gas production emission factors. For well sites and gathering and boosting compressor stations, these factors were from the *Protocol for Equipment Leak Emission Estimates* ("1995 Protocol") as incorporated into AP-42[23] for non-thief hatch fugitive emissions components. The emission factors in the 1995 Protocol 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 ratios as described in the 2011 Gas Composition Memorandum developed for the 2012 NSPS.[24]

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 natural gas production sites located in seven basins

[23] U.S. EPA, Protocol for Equipment Leak Emission Estimates, Table 2-4, November 1995. (EPA-453/R-95-017)
[24] 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.

across the U.S.[25] A description of this study and the development of the emission factor used, 0.1296 kg TOC/hr/thief hatch, is described in detail in the 2018 Proposal TSD (Section 2.3.5).[26]

The EPA received comments on the 2018 NSPS OOOOa proposal that indicated that the use of these emissions factors significantly overestimate fugitive emissions, while other comments were received that provided analyses suggesting that the proposed approach significantly underestimated fugitive emissions. Detailed descriptions of these comments and data, along with the EPA's analyses and response, can be found in Section V.B of the final rule preamble and in the memorandum included as Attachment 1 of this TSD.[27]

The July 2019 study published in Elementa previously discussed in Section 2.3.2 included measured fugitive emissions from well sites and gathering and boosting stations.[28] In that study, fugitive emissions were detected on equipment as defined in 40 CFR part 98, subpart W, using both OGI and Method 21. Fugitive emissions were documented as detected with OGI and Method 21 independently and as detected by both methods. Every detected fugitive emission was then quantified using an augmented protocol with a high volume sampler.[29] A total of 331 leaks were identified across the 67 sites. Utilizing the supplemental information submitted with the study, we converted the measured emissions rates from standard cubic feet per hour (scfh) methane to tons per year (tpy) for well sites and gathering and boosting stations. Three types of well sites were defined by the study: central production, well production, and well site. We evaluated the average emissions from each well site type and from the collection of all well sites. These emissions are presented in Table 2-11.

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[25] 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.
[26] EPA-HQ-OAR-2017-0483-0040.
[27] Memorandum. Summary of Data Received on the October 15, 2018 Proposed Amendments to 40 CFR Part 60, Subpart OOOOa Related to Model Plant Fugitive Emissions. February 10, 2020.
[28] Pacsi, AP, et al. 2019. Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. Elem Sci Anth, 7: 29. DOI: *https://doi.org/10.1525/elementa.368.*
[29] See study report for more information on procedures.

Table 2-11. Average Measured Emissions from Pasci, et al. (2019)

Site Type	Methane Emissions (tpy)	
	Gas Wells[30]	Oil Wells
Central Production	3.76	0.06
Well Production	2.14	6.94
Well Site	1.47	0.21
Average Well Sites	3.01	1.91
Gathering and Boosting	8.86	6.20

After consideration of the available information, the EPA determined that the use of the 1995 Protocol factors was still appropriate. The emissions factors used to estimate the emissions from well sites and gathering and boosting stations are provided in Table 2-12.

Table 2-12. Oil and Natural Gas Average TOC Emissions Factors Used to Calculate Baseline Emissions from Oil Wells and Gathering and Boosting Compressor Stations

Component Type	Component Service	Uncontrolled Emissions Factor[a] (kg TOC/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%).

For transmission and storage compressor stations, the emissions factors used component-specific methane emissions factors from the 1996 EPA/GRI study. For the final rule there was no change to these factors, which are provided in Table 2-13. The methane emissions calculated using these factors were converted to VOC using methane/VOC weight ratios as described in the 2011 Gas Composition Memorandum developed for the 2012 NSPS.[31] We received comments on the 2018 proposal that emissions reported through the GHGRP should be used instead of the 1996 EPA/GRI study emission

[30] The study does not provide a definition of gas well or oil well, therefore, it is assumed for purposes of comparison that oil wells are those with GOR <300 and gas wells are those with GOR >300.

[31] 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.

factors. We evaluated the use of the GHGRP reported emissions in a separate technical memorandum that is included as Attachment 2 to this TSD.[32]

Table 2-13. 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 2-14 summarizes the calculated baseline fugitive emissions for each of these model plants. Specifically, Table 2-14a provides emissions for the well site model plants and Table 2-14b for the compressor station model plants.

[32] Memorandum. Baseline Emissions for Compressor Stations Based on Subpart W Fugitive Emissions Data. January 23, 2020.

Table 2-14a. 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	VOC[b]
Natural 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
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
Oil Well Site with Associated Gas				
Valves	55	4.5E-03	1.66	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	3.04	0.85
Low Production Natural Gas Well Site				
Valves	65	4.5E-03	1.96	0.54
Flanges	0	3.9E-04	0.00	0.00
Connectors	233	2.0E-04	0.31	0.09
OEL	8	2.0E-03	0.11	0.03
PRV	4	8.8E-03	0.24	0.07
Thief Hatch	1	0.1296	0.87	0.24
		Total	3.48	0.97
Low Production Oil Well Site				
Valves	15	4.5E-03	0.45	0.13
Flanges	28	3.9E-04	0.07	0.02
Connectors	22	2.0E-04	0.03	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	1.54	0.43

Model Plant Component Type	Model Plant Component Count	Uncontrolled Emissions Factor[a] (kg/hr/component)	Uncontrolled Emissions (tpy)	
			Methane	VOC[b]
Low Production Oil Well Site with Associated Gas				
Valves	29	4.5E-03	0.87	0.24
Control Valves	28	3.9E-04	0.07	0.02
Connectors	70	2.0E-04	0.09	0.03
OEL	1	2.0E-03	0.01	0.00
PRV	2	8.8E-03	0.12	0.03
Thief Hatch	1	0.1296	0.87	0.24
		Total	2.04	0.57
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	0.70	0.19
Oil Wellhead Only				
Valves	10	4.5E-03	0.30	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	0.30	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.] VOC emissions calculated using 0.193 weight ratio for methane/TOC for well sites obtained from the 2011 Gas Composition Memorandum.

Table 2-14b. 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	439	4.5E-03	13.253	3.684
Flanges	0	3.9E-04	0.0	0.0
Connectors	1,308	2.0E-04	1.755	0.488
OEL	33	2.0E-03	0.443	0.123
PRV	20	8.8E-03	1.181	0.328
		Total	16.63	4.62
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.

2.4 Control Techniques

As shown in the 2016 NSPS Final TSD, EPA has previously evaluated the cost of using OGI or Method 21 for the detection of fugitive emissions in its BSER analysis for reducing fugitive emissions at well sites and compressor stations. In the 2016 NSPS OOOOa, EPA determined OGI to be the BSER but provided Method 21 as an alternative.[33] Based on a review of various state regulations,[34] OGI and Method 21 remain the main detection technologies for identifying fugitive emissions, and no specific information was provided as part of the reconsideration that identified any specific new detection technologies or control techniques for us to evaluate as BSER. Therefore, for purposes of this reconsideration, other detection technologies or control techniques were not evaluated. However, the use of OGI and Method 21 at various monitoring frequencies for each of the updated model plants was re-evaluated. The following sections describe the EPA's 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 basic elements of a fugitive emissions detection and repair program with OGI include the periodic monitoring for leaks, the repair of leaks identified, and the documentation of the activities. Specifically, these requirements include the 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 requirements also address the repair or replacement of 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). While the regulation includes requirements regarding these elements, each company needs to develop a monitoring plan that specifically describes how these requirements will be met at their well sites or compressor stations.

The following sections address the EPA's evaluation of the OGI program for well sites and compressor stations. Specifically, the emission reduction potential for OGI programs is provided in Section 2.4.1.1, the costs in Section 2.4.1.2, and the secondary impacts under Section 2.4.2.3 of this document.

2.4.1.1 OGI Emission Reduction Potential

For the analysis associated with the 2018 NSPS OOOOa proposal the EPA applied the following reduction percentages for OGI programs at different monitoring frequencies: 30 percent for biennial monitoring, 40 percent for annual monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring. A number of commenters provided input regarding these values and additional information from other sources, as described below.

[33] 81 FR 35846.

[34] 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.

Canadian Association of Petroleum Producers (CAPP) Study. During development of the 2018 NSPS OOOOa proposal, one stakeholder asserted that annual monitoring was appropriate for compressor stations, stating that the estimated control efficiency for quarterly monitoring should be 90 percent instead of 80 percent and annual monitoring should be 80 percent instead of 40 percent, based on the stakeholder's interpretation of results by a study conducted by CAPP.[35] In response to this information, the EPA reviewed the report and was unable to conclude that annual OGI monitoring would achieve 80 percent emissions reductions, as stated by the stakeholder.[36] In its submission of public comments on the proposal, and in subsequent clarifying discussions, the stakeholder continued to assert that the EPA had understated the emissions reductions achieved with annual monitoring.[37] As discussed below, we have re-evaluated the information provided in the CAPP report.

In 2005, CAPP developed emissions factors and issued a national inventory of GHG, criteria air contaminant, and hydrogen sulphide emissions by the upstream oil and gas industry.[38] In 2007, CAPP developed Best Management Practices (BMPs) for fugitive emissions from upstream oil and gas.[39] While not a regulation, these BMPs included recommended methods to reduce fugitive emissions, including the adoption of a directed inspection and maintenance program and the use of specific controls. In 2014, CAPP issued a report that updated the emissions factors developed in 2005, and that report estimated a net-weighted decrease of component-specific emissions of approximately 75 percent.[40] It is unclear from the 2014 report if the decrease is entirely the result of emission reduction achieved from implementation of the BMPs or if the decrease is also associated with improvements in emissions factors since 2005.

The EPA evaluated these three reports to determine if the control efficiency of OGI should be adjusted based on any information from CAPP. First, we evaluated the information in Tables 9 and 10 of the 2014 report. These tables include the emissions factors estimated using the two methodologies discussed in the 2014 report (Table 9) and the final updated emissions factors after consolidation of the two methodologies (Table 10). Table 10 also provided leaker counts and component counts. While there is uncertainty related to the component counts (*i.e.,* where no components were reported in the total count

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[35] Canadian Association of Petroleum Producers, "Update of Fugitive Equipment Leak Emission Factors," prepared for Canadian Association of Petroleum Producers by Clearstone Engineering, Ltd., February 2014.
[36] See memorandum *EPA Analysis of Fugitive Emissions Data Provided by INGAA* located at Docket ID No. EPA-HQ-OAR-2017-0483-0060. August 21, 2018.
[37] See Docket ID No. EPA-HQ-OAR-2017-0483-1002 and memorandum *April 30, 2019 Meeting with INGAA* located at Docket ID No. EPA-HQ-OAR-2017-0483.
[38] Canadian Association of Petroleum Producers, "A National Inventory of Greenhouse Gas (GHG), Criteria Air Contaminant (CAC), and Hydrogen Sulphide (H2S) Emissions by the Upstream Oil and Gas Industry," September 2004.
[39] Canadian Association of Petroleum Producers, "Best Management Practice. Management of Fugitive Emissions at Upstream Oil and Gas Facilities," January 2007.
[40] Canadian Association of Petroleum Producers, "Update of Fugitive Equipment Leak Emission Factors," prepared for Canadian Association of Petroleum Producers by Clearstone Engineering, Ltd., February 2014.

but emissions were reported, the number of components is assumed to equal the number of components with emissions), we used these counts as provided in the study to determine the emissions from leakers, in kilograms per hour (kg/hr), using both the 2005 and updated 2014 emissions factors. In order to evaluate whether a specific component was potentially monitored quarterly or annually, we divided components by the recommended monitoring frequencies included in Table 4 of the 2007 CAPP BMPs to assign the emissions to individual component types and monitoring frequencies. With this information, we were able to determine the difference in emissions between the 2005 and 2014 reports for individual components and assume the emissions reductions achieved for those components at the recommended frequencies. This is a similar process that was used by the commenter in their separate evaluation of the studies.

Through this analysis, we noted that open-ended lines had higher emissions than compressor seals in the 2005 inventory, and approximately a 90 percent reduction in emissions from open-ended lines specifically, in the 2014 study. Therefore, we examined open-ended lines in further detail. In the 2005 report, the confidence limits for open-ended lines are -60% to +170%, which means there is essentially no confidence in the 2005 emissions factors for this component type. This alone would indicate that any updated emissions factors in 2014 are not directly the result of reduced emissions from monitoring and repair, but are instead the result of more or better information which decreases the uncertainty of the emissions factor. Further examination of the 2005 inventory shows that open-ended lines were assigned a control factor of 1, which results in a leak rate of 0. This control factor assumes that all open-ended lines are equipped with a closure device (*e.g.,* cap, plug, blind flange, or secondary valve). The use of this control factor would suggest that open-ended lines have no emissions, yet the inventory and subsequent 2014 study included emissions. Thus, it is not clear to the EPA whether the emissions attributed to open-ended lines are based on the lack of a closure device, a leak past a closure device, or a combination of these factors. In the 2014 report, the average emissions factor for open-ended lines was determined using the total reported emissions for open-ended lines plus the total "no leak" emissions (using factors developed in 1992) divided by the total number of open-ended lines monitored. As previously stated, there is considerable uncertainty in the number of open-ended lines that were actually monitored at the facilities included in the 2014 report. While the 2014 report states that open-ended lines fitted with a closure device are not considered open-ended lines, there is uncertainty about whether the only reported leaks are from open-ended lines that are not controlled, especially since the BMPs specifically state a closure device should be used to control emissions. Given the uncertainties in the 2005 emissions factor, the control status of open-ended lines, and the component counts, we are unable to conclude the difference in emissions is due solely to annual monitoring using OGI. Despite these uncertainties, if we assumed the differences were due to monitoring alone, it is important to determine which open-ended lines are monitored annually and which are monitored quarterly. To do that, we evaluated Tables 12 and 13 of the 2014 report, which include default component counts by equipment or process (Table 12) and number of equipment or processes per jurisdiction reporting (Table 13). This allowed us to estimate the number of open-ended lines associated with compressors (and likely monitored quarterly), which we estimate is 65% of the open-ended lines. Attributing the emissions from 65% of the open-ended lines to quarterly monitoring results in emissions reductions of 92% for quarterly monitoring and 56% for annual monitoring. Based on this analysis, we are unable to conclude that the CAPP study demonstrates annual OGI monitoring would achieve an 80% reduction in emissions as stated by the commenter.

Stanford University Model. Another commenter provided information related to the emissions reductions achieved when using OGI at the various monitoring frequencies.[41] The commenter referenced a study performed by Dr. Arvind Ravikumar as supporting the EPA's estimates of emissions reductions for annual and semiannual monitoring using OGI.[42] This study utilized the Fugitive Emissions Abatement Simulation Toolkit (FEAST) model that was developed by Stanford University to simulate emissions reductions achieved at the various monitoring frequencies. The study used information from the EPA's model plant analysis for the 2016 NSPS OOOOa final rule, including the site-level baseline emissions. Emissions reductions were estimated at 32% for annual monitoring, 54% for semiannual monitoring, and 70% for quarterly monitoring.

Comparison with Method 21 Effectiveness. As previously stated in the 2018 Proposal TSD,[43] data from the Synthetic Organic Chemicals Manufacturing Industry (SOCMI) in the 1995 Equipment Leak Protocol Document (1995 Protocol) was used to estimate the Method 21 effectiveness at the various monitoring frequencies. In the 2018 Proposal TSD, we stated, "it is not possible to correlate OGI detection capabilities with a Method 21 instrument reading, provided in ppm. However, based on 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."[44] We received comments asserting that the EPA inappropriately used Method 21 effectiveness estimates based on SOCMI, which are not comparable or appropriate for the oil and natural gas industry. In response to these comments, we have updated the Method 21 effectiveness estimates using information for the oil and gas industry from the 1995 Protocol Document. We used the

[41] See Docket ID No. EPA-HQ-OAR-2017-0483-2041.
[42] See Appendix D to Docket ID No. EPA-HQ-OAR-2017-0483-2041.
[43] See Docket ID No. EPA-HQ-OAR-2017-0483-0040.
[44] See Docket ID No. EPA-HQ-OAR-2017-0483-0040, at page 25.

same methodology used in 2016 to determine the Method 21 effectiveness, but applied the average leak rates and emissions factors that are specific to the oil and gas industry.[45,46] The revised analysis estimates emissions reductions when using Method 21 to be 40% for annual monitoring, 54% for semiannual monitoring, and 67% for quarterly monitoring when using the average effectiveness between 500 ppm and 10,000 ppm. We believe that estimated emission reductions using OGI would likely be higher because OGI has been demonstrated as capable of detecting large emissions not otherwise detected using Method 21, such as emissions from thief hatches on controlled storage vessels.[47]

Conclusion. The result of EPA's consideration of the information provided in the comments was to determine that the effectiveness values used at proposal noted above were appropriate. Tables 2-15 and 2-16 provide the estimated emission reductions of OGI-based programs at varying frequencies of monitoring for well sites and compressor stations, respectively.

[45] See US EPA, "1995 Protocol for Equipment Leak Emission Estimates Emission Standards" located at Docket ID No. EPA-HQ-OAR-2017-0483-0002.
[46] See TSD located at Docket ID No. EPA-HQ-OAR-2017-0483.
[47] Pacsi, AP, et al. 2019. Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. Elem Sci Anth, 7: 29. DOI: *https://doi.org/10.1525/elementa.368.*

Table 2-15. Model Plant Emission Reductions for OGI Monitoring and Repair – Well Sites

Affected Facility	Emission Reduction (tpy)	
	Methane	VOC
Biennial Monitoring		
Low Production Gas Well Sites	1.04	0.290
Low Production Oil Well Sites (GOR < 300)	0.46	0.128
Low Production Oil Well Sites (GOR > 300)	0.61	0.170
Annual Monitoring		
Gas Well Sites	2.36	0.66
Oil Well Sites (GOR < 300)	0.82	0.23
Oil Well Sites (GOR > 300)	1.22	0.34
Low Production Gas Well Sites	1.39	0.387
Low Production Oil Well Sites (GOR < 300)	0.62	0.171
Low Production Oil Well Sites (GOR > 300)	0.82	0.227
Semiannual Monitoring		
Gas Well Sites	3.55	0.99
Oil Well Sites (GOR < 300)	1.23	0.34
Oil Well Sites (GOR > 300)	1.82	0.51
Low Production Gas Well Sites	2.09	0.581
Low Production Oil Well Sites (GOR < 300)	0.92	0.257
Low Production Oil Well Sites (GOR > 300)	1.22	0.340
Quarterly Monitoring		
Gas Well Sites	4.73	1.315
Oil Well Sites (GOR < 300)	1.65	0.457
Oil Well Sites (GOR > 300)	2.43	0.676

Table 2-16. Model Plant Emission Reductions for OGI Monitoring and Repair – Compressor Stations

Affected Facility	OGI Monitoring (tpy)	
	Methane	VOC
Annual Monitoring		
Gathering & Boosting	6.7	1.85
Transmission	16.2	0.45
Storage	57.0	1.58
Semiannual Monitoring		
Gathering & Boosting	10.0	2.8
Transmission	24.2	0.7
Storage	85.5	2.4
Quarterly Monitoring		
Gathering & Boosting	13.3	3.7
Transmission	32.3	0.9
Storage	114.0	3.2

2.4.1.2 Cost Impacts of OGI-Based Program

Model Plant Costs. As noted above, there are three basic elements of a fugitive emissions detection and repair program with OGI: (1) the periodic monitoring for leaks, (2) the repair of leaks identified, and (3) the documentation of the activities. There are costs associated with each of these elements. In addition, there are costs associated with planning and preparation. These planning and preparation costs include resources to read and understand the regulatory requirements, to develop a monitoring plan, and to develop a system to manage the information collected during the periodic monitoring and subsequent repairs.

For the 2018 NSPS OOOOa proposed amendments, costs for the following were included in estimating the cost of the OGI fugitive emission monitoring program:

- Reading of the rule and instructions,
- Development of a fugitive emissions monitoring plan,
- Initial and subsequent activities planning,
- Notification of compliance status,
- Cost for OGI monitoring,
- Annual repair costs,
- Costs to resurvey, and

- Preparation of annual reports.

There were a number of comments received on the 2018 NSPS OOOOa proposal indicating that the costs for developing and implementing an OGI-based program to comply with NSPS OOOOa were underestimated dating back to the 2016 final rule. In reviewing and assessing these comments, the EPA agreed with the commenters that the model plant costs for the use of OGI should be re-assessed. Specifically, the EPA reevaluated the cost burden of the existing fugitive emissions standards (*i.e.,* as finalized under the 2016 NSPS OOOOa) prior to considering any additional changes in this final rule that would affect those costs. In other words, this reassessment led to the development of a new "baseline" to which the costs associated with the final amendments would be compared.

The first step was to evaluate the cost elements listed above to determine if they best characterized the costs that would be incurred for an owner/operator developing and implementing an OGI-based fugitive emissions program. In reevaluating the cost elements, it was determined that the initial and subsequent planning activities were not specific enough to warrant inclusion. The EPA also noted that the notification of compliance status report was not required in the final 2016 NSPS OOOOa rule for well site and compressor fugitive component affected facilities and should not have been included in the OGI program costs.

Next, the previous estimate to develop a monitoring plan was examined. One commenter provided information on the range of costs that have been incurred by owners and operators to develop a monitoring plan since the rule has been in place.[48] These estimated costs range from $5,600 to $8,800, which is more than the previous monitoring plan estimate of $3,672 (which EPA based on 60 hours). The information provided by the commenter was based on a survey of actual hours spent for developing the monitoring plan and was around 80 hours. In examining the information provided by the commenter in further detail, it was noted that hourly rates are higher than the standard labor rate used in EPA's calculations ($70-$110 per hour vs $61.21 per hour), which could attribute to the difference in costs. Next, the EPA examined the assumption that the monitoring plan is a one-time cost for the company. Several commenters stated while most of the monitoring plan is associated with a one-time cost, the required site map and observation path require frequent updates as the equipment at the site changes. The same commenter provided an estimate of the cost to develop the initial site map and observation path for an individual site, and the cost of updating these items for each monitoring survey.[49] This information provided estimates that companies have already spent approximately $650 developing the individual site

[48] Letter from Mattew Todd, American Petroleum Institute to Karen Marsh, EPA. API Supplemental Cost Information. May 22, 2019.
[49] Id.

map and observation path for each site and an additional $150 updating these items for each monitoring survey. Based on this information, the EPA determined that it is appropriate to account for the necessary updates for the site map and observation path when estimating the cost burden of the rule in the model plant. Therefore, the fugitive emissions monitoring plan costs were separated into the following three items:

(1) develop company-wide fugitive emissions monitoring plan,

(2) develop site-specific fugitive monitoring plan (*i.e.,* site map and observation path), and

(3) management of change (site map and observation path).

The updated estimates associated with developing a monitoring plan for well sites under the existing standards are $2,448 to develop the general company-wide monitoring plan (assumes 22 well sites within a company defined area),[50] $400 to develop the site map and observation path for each site, and $184 to update the individual site map and observation path annually (based on semiannual monitoring). For gathering and boosting compressor stations, the EPA estimates that it costs $1,530 to develop a company-wide monitoring plan (assumes 7 stations per plan within a company defined area),[51] $400 to develop the site map and observation path for each site, and $367 to update the individual site map and observation path annually (based on quarterly monitoring). For both types of transmission and storage stations, the estimate of $3,672 to develop a site-specific monitoring plan was maintained and we have added $367 to update the individual site map and observation path annually (based on quarterly monitoring).

In further reevaluating cost elements of the previous fugitive emissions monitoring model plant, with respect to the recordkeeping costs, we were unable to locate specific estimates for recordkeeping costs for the existing standards (*e.g.,* database management of records, tracking of repairs, QA/QC of records). Therefore, a new line item was added to the baseline estimate of the actual cost of the existing standards. There are extensive records required for each survey that is performed, regardless of the frequency, therefore the EPA recognizes that appropriate data management is critical to ensuring compliance with the standards. As such, the EPA evaluated costs for the set-up of a database system which ranged from commercially available options to customized systems. Because there are commercial systems currently available that allow owners and operators to maintain records in compliance with the standards, the EPA did not find it appropriate to apply customized system costs to determine an average or

[50] The number of well sites owned and operated by companies was calculated using data from the Fort Worth study. An analysis of additional information from 2017 compliance reports was consistent with the previously calculated number of well sites per company of 22.

[51] For gathering and boosting stations, this cost was assumed to be shared with other 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, there would be an estimated 7 gathering and boosting stations.

range of costs. Therefore, the initial database set-up fee is estimated as $18,607[52] based on 22 well sites, 7 gathering and boosting stations, or individual transmission and storage stations. That is, for every 22 well sites, it is estimated that it will cost $18,607 to obtain and set-up a database for records management. In addition to this initial set-up fee, there are annual licensing fees that include technical support and updates to software. Additional information received after the 2018 NSPS OOOOa proposal from API indicated that average ongoing annual costs to maintain the recordkeeping database, including IT Support, Environmental Health and Safety (EHS) support, upgrades, etc. was $868 based on facilities surveyed by API. In addition, information obtained from Krinkle (a Leak Detection and Repair (LDAR) database application) indicated there are annual fees of $70 for its LDAR application suite.[53] Taking into account both estimates obtained from industry, an average ongoing annual fee of approximately $470 was incorporated into the model plants. Finally, there is an additional burden associated with tracking observed fugitive emissions and repairs, such as scheduling repairs and quality control of the data. Based on information provided by commenters[54,55] the EPA estimates that additional recordkeeping and data management costs are $430 for well sites and $860 for compressor stations.

Comments received on the 2018 NSPS OOOOa proposal noted concerns related to the occurrence rate of fugitive emissions, or the percentage of leaking components identified with fugitive emissions during each survey that needed repair used in the proposal analysis. This impacts the repair and resurvey costs in the model plant analysis. In the proposal analysis, it was assumed that each monitoring survey would identify four components with fugitive emissions. That is, when a site is monitored annually, the EPA estimated four total components leaking for that year, but if that same site were monitored semiannually, the EPA estimated eight total components leaking for that year. While more frequent monitoring does have a different occurrence rate, the difference between semiannual and annual is not 100%. In the proposal analysis of Method 21 effectiveness (assuming a 500-ppm repair threshold), the leak occurrence rates for semiannual and annual monitoring are 3.65% and 4.72%, respectively. That means that during an annual Method 21 survey, there would be an estimated 4.72% of the components with fugitive emissions, whereas for each semiannual Method 21 survey there would be an estimated 3.65% of the components with fugitive emissions. For purposes of updating the model plant analysis

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[52] Based on the cost of a data collection system per company of $14,500, adjusted to $2016 using an inflation factor of 1.28322 obtained from Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA. Analysis of Emissions Reduction Techniques for Equipment Leaks. December 21, 2011. EPA-HQ-OAR-2010-0869-0029.
[53] Cost of annual database maintenance and license fee for Krinkle obtained from https://www.krinkleapps.com/ldar-tracker.
[54] Letter from Mattew Todd, American Petroleum Institute to Karen Marsh, EPA. API Supplemental Cost Information. May 22, 2019.
[55] Memorandum of May 1, 2019 Meeting with GPA Midstream (GPA). Karen Marsh, U.S. EPA Office of Air Quality Planning and Standards, Sector and Policies and Programs Division, to Docket EPA-HQ-OAR-2017-0483. September 25, 2019.

where OGI is the BSER, these specific occurrence rates were not applied, and instead the annual compliance report information for the 2017 and 2018 reporting years were evaluated.[56] For this analysis the EPA retrieved reports from compliance and emissions data reporting interface (CEDRI) that included fugitive emissions information for 2,800 well sites. The average number of fugitive components reported as leaking were determined from these reports. An estimate of three components per annual survey and two components per semiannual and quarterly survey were applied to the well site model plant analysis. These values are similar to those provided by several commenters.[57, 58] For the sites identified as possibly low production sites, an estimated two leaks were identified annually. The results were that the repair and resurvey costs for well plants are slightly lower in the updated baseline costs for both the well site and low production well site model plants.

For gathering and boosting compressor stations, the 2018 NSPS OOOOa proposal analysis assumed that there would be 46 leaks found per survey at gathering and boosting compressor stations. The EPA examined the information provided by the GPA Midstream in comments on the 2018 NSPS OOOOa proposed amendments and determined that on average 11 components were identified as leaking during the year.[59] The model plant cost analysis was revised to apply this value for all monitoring frequencies because the number of reported leaks varied widely in the dataset. This significant reduction in the number of leaks that would need repair resulted in a substantial reduction in the estimated repair costs for gathering and boosting stations.

For transmission and storage compressor stations the EPA previously assumed a leak rate of 45 leaks per survey at transmission compressor stations and 93 leaks per survey at storage compressor stations. For the updated analysis, the EPA obtained information regarding the average number of components found leaking per year per compressor station as reported to the EPA's GHGRP. These leak rates were 24 components per survey for transmission stations and 59 for storage stations. Similar to gathering and boosting stations, we applied these values for all frequencies as the average number of repairs needed over the course of a year. This significant reduction in the number of leaks that need repair resulted in a substantial reduction in the estimated repair costs for transmission and storage stations.

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[56] See Attachment 3.
[57] Todd, Matthew, American Petroleum Institute. Comments on Docket ID No. EPA-HQ-OAR-2017-0483; EPA's "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration; Proposed Rule"; 83 Fed. Reg. 52056 (October 15, 2018). December 17, 2018. Docket Item Number EPA-HQ-OAR-2017-0483-0801.
[58] Environmental Defense Fund, et.al. Comments on Docket ID No. EPA-HQ-OAR-2017-0483; EPA's "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration; Proposed Rule"; 83 Fed. Reg. 52056 (October 15, 2018). December 17, 2018. Docket Item Number EPA-HQ-OAR-2017-0483-2041.
[59] Hite, Matthew, GPA Midstream Association. Comments on Docket ID No. EPA-HQ-OAR-2017-0483; EPA's "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration; Proposed Rule"; 83 Fed. Reg. 52056 (October 15, 2018). December 17, 2018. Docket Item Number EPA-HQ-OAR-2017-0483-1261.

The last element that was reevaluated from the previous estimate was the reporting costs associated with the requirements in the 2016 NSPS OOOOa. One commenter asserted that they spent over 500 hours reporting information in CEDRI for their sources.[60] The EPA examined the information reported to CEDRI for this commenter and concluded that they have reported information for approximately 100 well sites, which would equate to 5 hours per site. This is similar to EPA's estimate of 4 hours per well site, therefore the reporting cost estimate when determining the actual costs of recordkeeping and reporting associated with the existing standards has not been revised.

Table 2-17 provides the previous model plant cost estimates with the updated cost estimates for well sites. Tables 2-18a, 2-18b, and 2-18c provide the same comparison for compressor stations. Note that these tables present one monitoring frequency (semiannual for well sites and quarterly for compressor stations) for illustrative purposes. Details on the costs for each monitoring frequency evaluated are provided in the model plant spreadsheets which are included as attachments to this TSD.

[60] EPA-HQ-OAR-2017-0483-0757.

Table 2-17. Comparison of Previous and Revised Model Plant Costs for Well Sites – Baseline for 2016 Final Rule

Cost Component	Costs for OGI Program – Semiannual Monitoring		
	Previous Estimate	Updated Estimate	Updated Estimate – Low Production
One-Time Initial Costs			
Read rule and instructions (per company)	$245	$245	$245
Develop Company-Wide Fugitives Monitoring Plan - Well Sites - 60.5397a(c) (per company)		$2,448	$2,448
Development of Equipment Leaks Monitoring Plan (per company)	$3,672		
Initial Activities Planning (per company)	$1,959		
Notification of Initial Compliance Status (per company	$1,347		
First Year Total Cost per Company	$7,222	$2,693	$2,693
Develop Site-Specific Fugitives Monitoring Plan - Well Sites - 60.5397a(d) (per well site)		$398	$398
Recordkeeping Database system set-up fee (per well site)		$846	$846
First Year Total "Capital" Cost per Well Site (assuming 22 well sites per company)	$328	$1,366	$1,366
Ongoing Annual Costs (all per well site)			
Subsequent Activities Planning	$89		
OGI Camera Survey	$1,271	$911	$643
Repair Costs	$633	$316	$158
Repaired Component Resurvey (OGI/M21 Device)	$41	$20	$10
Annual Recordkeeping Database Maintenance and License fee		$469	$469
Additional recordkeeping/data management costs		$430	$430
Management of Change (Site Map/Observation Path)		$184	$184
Annual Report	$245	$245	$245
Annual Cost per Well Site	$2,278	$2,575	$2,139
Annual Cost Per Well Site with Amortized Capital Cost	$2,333	$2,804	$2,368

Table 2-18a. Comparison of Previous and Revised Model Plant Costs for Gathering and Boosting Compressor Stations – Baseline for 2016 Final Rule

Cost Component	Costs for OGI Program –Quarterly Monitoring	
	Previous Estimate	Updated Estimate
One-Time Initial Costs		
Read rule and instructions (per company)	$245	$245
Develop Company-Wide Fugitives Monitoring Plan - 60.5397a(c) (per company)		$1,530
Recordkeeping Database system set-up fee		$18,607
Development of Equipment Leaks Monitoring Plan (per company)	$3,672	
Initial Activities Planning (per company)	$1,959	
Notification of Initial Compliance Status (per company)	$428	
First Year Total Cost per Company	$6,304	$20,382
Develop Station-Specific Fugitives Monitoring Plan – Compressor Stations - 60.5397a(d) (per gathering and boosting station)		$398
First Year Total "Capital" Cost per Station (assuming 7 gathering and boosting stations per company)	$901	$3,310
Ongoing Annual Costs (all per station)		
Subsequent Activities Planning	$1,469	
OGI Camera Survey	$9,200	$9,200
Repair Costs	$14,552	$870
Repaired Component Resurvey (OGI/M21 Device)	$938	$56
Annual Recordkeeping Database Maintenance and License fee		$472
Additional recordkeeping/data management costs		$860
Management of Change (Site Map/Observation Path)		$367
Annual Report	$245	$245
Annual Cost per Station	$26,404	$12,070
Annual Cost Per Station with Amortized Capital Cost	$26,555	$12,624

Table 2-18b. Comparison of Previous and Revised Model Plant Costs for Transmission Compressor Stations – Baseline for 2016 Final Rule

Cost Component	Costs for OGI Program – Quarterly Monitoring	
	Previous Estimate	Updated Estimate
One-Time Initial Costs		
Read rule and instructions (per station)	$245	$245
Develop Station-Specific Fugitives Monitoring Plan - 60.5397a(c) and (d)		$3,672
Recordkeeping Database system set-up fee		$18,607
Development of Equipment Leaks Monitoring Plan (per station)	$3,672	
Initial Activities Planning (per company)	$1,959	
Notification of Initial Compliance Status (per station)	$61	
First Year Total “Capital” Cost per Station	$5,937	$22,524
Ongoing Annual Costs (all per station)		
Subsequent Activities Planning	$1,469	
OGI Camera Survey	$9,200	$9,200
Repair Costs	$14,235	$3,537
Repaired Component Resurvey (OGI/M21 Device)	$918	$124
Annual Recordkeeping Database Maintenance and License fee		$472
Additional recordkeeping/data management costs		$860
Management of Change (Site Map/Observation Path)		$367
Annual Report	$245	$245
Annual Cost per Station	$26,067	$14,804
Annual Cost Per Station with Amortized Capital Cost	$27,062	$18,576

Table 2-18c. Comparison of Previous and Revised Model Plant Costs for Storage Compressor Stations – Baseline for 2016 Final Rule

Cost Component	Costs for OGI Program – Quarterly Monitoring	
	Previous Estimate	Updated Estimate
One-Time Initial Costs		
Read rule and instructions (per station)	$245	$245
Develop Station-Specific Fugitives Monitoring Plan - 60.5397a(c) and (d)		$3,672
Recordkeeping Database system set-up fee		$18,607
Development of Equipment Leaks Monitoring Plan (per station)	$3,672	
Initial Activities Planning (per company)	$1,959	
Notification of Initial Compliance Status (per station)	$61	
First Year Total "Capital" Cost per Station	$5,937	$22,524
Ongoing Annual Costs (all per station)		
Subsequent Activities Planning	$1,469	
OGI Camera Survey	$9,200	$9,200
Repair Costs	$29,420	$7,014
Repaired Component Resurvey (OGI/M21 Device)	$1,897	$303
Annual Recordkeeping Database Maintenance and License fee		$472
Additional recordkeeping/data management costs		$860
Management of Change (Site Map/Observation Path)		$367
Annual Report	$245	$245
Annual Cost per Station	$42,231	$18,461
Annual Cost Per Station with Amortized Capital Cost	$43,225	$22,233

After incorporating the revisions to the 2016 NSPS OOOOa baseline model plant costs discussed above, the EPA considered the suggested changes to the fugitive monitoring requirements from the comments and re-evaluated what information was necessary to demonstrate compliance with the requirements of the fugitive emissions program. Detailed discussion of these comments, EPA responses, and resulting changes to the requirements, are provided in Sections V.B and VI.B of the final rule preamble. Several of these changes result in adjustments to the model plant costs. The following discussion presents the specific rule changes that resulted in the revised model plant costs.

In the final amendments, the requirement for a site map and observation path when OGI is used to perform fugitive emissions surveys has been removed. This requirement was in place to ensure that all fugitive emissions components could and would be imaged during each survey. Through further examination, we agree with the commenters that a site map and observation path are only one way to ensure all components are imaged. We are replacing the specified site map and observation path with a requirement to include procedures to ensure that all fugitive emissions components are monitored during each survey. These procedures may include a site map and observation path, an inventory, or narrative of the location of each fugitive emissions component, but may also include other procedures not listed here. These company-defined procedures are consistent with other requirements for procedures in the monitoring plan, such as the requirement for procedures for determining the maximum viewing distance and maintaining this viewing distance during a survey. As previously stated, we had not accurately accounted for the ongoing cost of updating the site map and observation path as changes occur at the site. Based on information provided by one commenter, we estimate this amendment will save each site $580 with the semiannual monitoring frequency. These cost savings are based on an initial cost of $400 to develop the site map and observation path, plus $180 to update the site map or observation path each year, based on a semiannual monitoring frequency. These savings apply to the well site model plants and gathering and boosting stations. For transmission or storage stations, this amendment will save each station $180 to update the site map or observation path each year, based on the semiannual frequency. The original station-specific fugitives monitoring plan estimate as required in the 2016 NSPS OOOOa for transmission and storage compressor stations has been maintained and is representive of the costs with the amendments.

The EPA is amending the recordkeeping requirements to remove records of each repair attempt and the number and type of components not repaired during the monitoring survey. While it is difficult to quantify the reduction in cost burden of the removal of these records, the EPA has estimated a reduction in cost of 25%, or $107 per site per year.

The EPA is also amending the reporting requirements to streamline reporting. Similar to the recordkeeping changes identified in the previous paragraph, it is difficult to estimate the reduced cost burden of each of these individual items. Therefore, the EPA has estimated a burden reduction of 25%, or $61 per site per annual report.

In summary, the cost burden estimates for recordkeeping and reporting based on the amendments in this final rule will reduce the burden of the rule. The estimated annualized recordkeeping and reporting costs for this final rule, on a per site basis, are approximately $1,100 per well site, $1,750 per gathering and boosting station, and $5,000 per transmission and storage station. This results in an annualized burden reduction of approximately 27% for well sites, 30% for gathering and boosting compressor stations, and 12% for transmission and storage stations.

For the final amendments, a summary of the company-level model plant costs are as follows:

- Reading of the rule and instructions would take 1 person 4 hours to complete at a cost of $245.
- For well sites, development of a company-wide fugitive emission monitoring plan would take 1 person 40 hours to complete at a cost of $2,448. For gathering and boosting stations, development of a company-wide fugitive emission monitoring plan would take 1 person 25 hours to complete at a cost of $1,530. For transmission and storage, development of a company-wide fugitive emission monitoring plan would take 1 person 60 hours to complete at a cost of $3,672.
- For well sites and compressor stations, the recordkeeping database system set-up fee would be $18,607 per company. For well sites, the cost would be $846 per well site assuming each company owns 22 well sites.

For the final amendments, a summary of the site/station-level model plant costs are as follows:

- The cost for OGI monitoring using an outside contractor was assumed to be $456 for a non-low production well site for each monitoring event ($322 for a low production)[61] and $2,300 for each compressor station monitoring event.[62]
- Annual repair costs were estimated to be $316 per monitoring event for well sites and $158 for low production well sites, $870 per monitoring event for gathering and boosting stations, $3,537 per monitoring event for transmission stations, and $7,014 per monitoring event for storage stations. For well sites, these costs were estimated assuming an average of 3 total leaks found per year (2 leaks for low production).[63] For gathering and boosting stations, these costs were estimated assuming an average of 11 total leaks found per year.[64] For transmission and storage, these costs

[61] Assumes 3.4 hours per survey for non-low production and 2.4 hours for low production based on OOOOa compliance reports and $134/hour contractor rate based on Colorado Department of Public Health and Environment (CDPHE) Regulatory Analysis. The survey time includes the travel time to and from the well site.
[62] Costs for contractor based OGI monitoring obtained from the Carbon Limits report.
[63] The leak percentage is based on information in Attachment B of "API Analysis of Subpart OOOOa Semi-Annual Leak Survey Data" submitted by API to EPA in public comments. See EPA-HQ-OAR-2017-0483-0801.
[64] The leak percentage is based on information provided by GPA in comments on the proposed reconsideration. See EPA-HQ-OAR-2017-0483-1261.

were estimated assuming an average of 24 and 59 total leaks found per year, respectively.[65] For well sites and compressor stations, 75 percent of leaks are repaired online and 25 percent or leaks 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 for well sites and $57.80 per hour for compressor stations. This assumes the company is able to perform the resurvey without retaining contractors.
- For well sites, costs associated with recordkeeping database maintenance and license fee was estimated at $221 for biennial monitoring, $452 for annual monitoring, and $469 for semiannual and quarterly monitoring. For compressor stations, costs associated with recordkeeping database maintenance and license fee was estimated at $447, $469 and $472, for annual, seminannual, and quarterly monitoring, respectively.
- Additional recordkeeping and data management costs for well sites were estimated at $161 for biennial monitoring and $323 for annual, semiannual, and quarterly monitoring. For compressor stations, the additional recordkeeping and data management costs were estimated at $645 for all monitoring frequencies compressor stations.
- Preparation of annual reports was estimated to take 1 person a total of 3 hours to complete at a cost of $184 for well sites and compressor stations.

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, the development of fugitive emissions monitoring plan, and the purchase and set-up of a recordkeeping database system. In 2016, the EPA assumed that each company defined area would require the purchase of an instrument to perform Method 21 monitoring for the resurvey. However, it is the EPA's 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 $21,300 per company defined area. Assuming that each company owns and operates 22 well sites within a company defined area,[66] the capital cost per well site was estimated to be $968. For gathering and boosting compressor stations the capital cost for reading the rule, development of fugitive emissions monitoring plan, and the purchase and set-up

[65] The number of leak was based on information submitted through Subpart W of the Greenhouse Gas Reporting Program.
[66] The number of well sites owned and operated by companies was calculated using data from the Fort Worth study. An analysis of additional information from 2017 compliance reports was consistent with the previously calculated number of well sites per company of 22.

of recordkeeping database system was calculated to be $20,382, 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 $2,912. For transmission and storage stations, the capital cost per facility was calculated to be $22,524.

For all oil and natural gas segments, the annual cost includes OGI survey, cost of repair of fugitive emissions found, resurvey of repaired components, recordkeeping database maintenance and license fee, additional recordkeeping and data management costs, preparation and submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. For our analysis EPA calculated the annual cost for annual, semiannual, and quarterly OGI surveys at well sites; biennial, annual, and semiannual for low production 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 are incurred in the years when monitoring does not occur. The OGI monitoring cost memorandum[67] 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.

Tables 2-19a and 2-19b for well sites, and Tables 2-20a, 2-20b, and 2-20c for compressor stations, provide a line-by-line comparison of the updated 2016 NSPS OOOOa model plant costs (updated as discussed above) to the model plant costs after the final amendments. Note that these tables present one monitoring frequency for illustrative purposes (semiannual for well sites and quarterly for compressor stations). Details on the costs for each monitoring frequency evaluated are provided in the model plant spreadsheets which are included as attachments to this TSD.

[67] 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.

Table 2-19a. Comparison of 2016 Baseline and Final Rule Model Plant Costs for Well Sites

Cost Component	Costs for OGI Program – Semiannual Monitoring	
	2016 Baseline Estimate	After Final Rule Changes
One-Time Initial Costs		
Read rule and instructions (per company)	$245	$245
Develop Company-Wide Fugitives Monitoring Plan - Well Sites - 60.5397a(c) (per company)	$2,448	$2,448
First Year Total Cost per Company	$2,693	$2,693
Develop Site-Specific Fugitives Monitoring Plan - Well Sites - 60.5397a(d) (per well site)	$398	$0
Recordkeeping Database system set-up fee (per well site)	$846	$846
First Year Total "Capital" Cost per Well Site (assuming 22 well sites per company)	$1,366	$968
Ongoing Annual Costs (all per well site)		
OGI Camera Survey	$911	$911
Repair Costs	$316	$316
Repaired Component Resurvey (OGI/M21 Device)	$20	$20
Annual Recordkeeping Database Maintenance and License fee	$469	$469
Additional recordkeeping/data management costs	$430	$323
Management of Change (Site Map/Observation Path)	$184	$0
Annual Report	$245	$184
Annual Cost per Well Site	$2,575	$2,223
Annual Cost Per Well Site with Amortized Capital Cost	$2,804	$2,384

Table 2-19b. Comparison of 2016 Baseline and Final Rule Model Plant Costs for Low Production Well Sites

Cost Component	Costs for OGI Program – Semiannual Monitoring	
	2016 Baseline Estimate	After Final Rule Changes
One-Time Initial Costs		
Read rule and instructions (per company)	$245	$245
Develop Company-Wide Fugitives Monitoring Plan - Well Sites - 60.5397a(c) (per company)	$2,448	$2,448
First Year Total Cost per Company	$2,693	$2,693
Develop Site-Specific Fugitives Monitoring Plan - Well Sites - 60.5397a(d) (per well site)	$398	$0
Recordkeeping Database system set-up fee (per well site)	$846	$846
First Year Total "Capital" Cost per Well Site (assuming 22 well sites per company)	$1,366	$968
Ongoing Annual Costs (all per well site)		
OGI Camera Survey	$643	$643
Repair Costs	$158	$158
Repaired Component Resurvey (OGI/M21 Device)	$10	$10
Annual Recordkeeping Database Maintenance and License fee	$469	$469
Additional recordkeeping/data management costs	$430	$323
Management of Change (Site Map/Observation Path)	$184	$0
Annual Report	$245	$184
Annual Cost per Well Site	$2,139	$1,787
Annual Cost Per Well Site with Amortized Capital Cost	$2,368	$1,949

Table 2-20a. Comparison of 2016 Baseline and Final Rule Plant Model Plant Costs for Gathering and Boosting Compressor Stations

Cost Component	Costs for OGI Program – Quarterly Monitoring	
	2016 Baseline Estimate	After Final Rule Changes
One-Time Initial Costs		
Read rule and instructions (per company)	$245	$245
Develop Company-Wide Fugitives Monitoring Plan - 60.5397a(c) (per company)	$1,530	$1,530
Recordkeeping Database system set-up fee (per company)	$18,607	$18,607
First Year Total Cost per Company	$20,382	$20,382
Develop Station-Specific Fugitives Monitoring Plan – Compressor Stations - 60.5397a(d) (per gathering and boosting station)	$398	$0
First Year Total "Capital" Cost per Station (assuming 7 gathering and boosting stations per company)	$3,310	$2,912
Ongoing Annual Costs (all per station)		
OGI Camera Survey	$9,200	$9,200
Repair Costs	$870	$870
Repaired Component Resurvey (OGI/M21 Device)	$56	$56
Annual Recordkeeping Database Maintenance and License fee	$472	$472
Additional recordkeeping/data management costs	$860	$645
Management of Change (Site Map/Observation Path)	$367	$0
Annual Report	$245	$184
Annual Cost per Station	$12,070	$11,426
Annual Cost Per Station with Amortized Capital Cost	$12,624	$11,914

Table 2-20b. Comparison of 2016 Baseline and Final Rule Model Plant Costs for Transmission Compressor Stations

Cost Component	Costs for OGI Program – Quarterly Monitoring	
	2016 Baseline Estimate	After Final Rule Changes
One-Time Initial Costs		
Read rule and instructions (per station)	$245	$245
Develop Station-Specific Fugitives Monitoring Plan - 60.5397a(c) and (d)	$3,672	$3,672
Recordkeeping Database system set-up fee	$18,607	$18,607
First Year Total "Capital" Cost per Station	$22,524	$22,524
Ongoing Annual Costs (all per station)		
OGI Camera Survey	$9,200	$9,200
Repair Costs	$3,537	$3,537
Repaired Component Resurvey (OGI/M21 Device)	$124	$124
Annual Recordkeeping Database Maintenance and License fee	$472	$472
Additional recordkeeping/data management costs	$860	$645
Management of Change (Site Map/Observation Path)	$367	$0
Annual Report	$245	$184
Annual Cost per Station	$14,804	$14,160
Annual Cost Per Station with Amortized Capital Cost	$18,576	$17,933

Table 2-20c. Comparison of 2016 Baseline and Final Rule Model Plant Costs for Storage Compressor Stations

Cost Component	Costs for OGI Program – Quarterly Monitoring	
	2016 Baseline Estimate	After Final Rule Changes
One-Time Initial Costs		
Read rule and instructions (per station)	$245	$245
Develop Station-Specific Fugitives Monitoring Plan - 60.5397a(c) and (d)	$3,672	$3,672
Recordkeeping Database system set-up fee	$18,607	$18,607
First Year Total "Capital" Cost per Station	$22,524	$22,524
Ongoing Annual Costs (all per station)		
OGI Camera Survey	$9,200	$9,200
Repair Costs	$7,014	$7,014
Repaired Component Resurvey (OGI/M21 Device)	$303	$303
Annual Recordkeeping Database Maintenance and License fee	$472	$472
Additional recordkeeping/data management costs	$860	$645
Management of Change (Site Map/Observation Path)	$367	$0
Annual Report	$245	$184
Annual Cost per Station	$18,461	$17,818
Annual Cost Per Station with Amortized Capital Cost	$22,233	$21,590

Cost of Control. The next step in the process was to determine the costs in relation to the emission reductions that would be achived by the fugitive emissions programs at the varying monitoring frequencies. This 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 emission reductions and the estimated cost for implementing an OGI fugitive emissions monitoring and repair program at the affected facilities, 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 compressor stations, 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 2-21, 2-22, 2-22, and 2-24 present a summary of the cost of control for methane and VOC for the various OGI monitoring frequency options (*i.e.,* biennial, annual, semiannual, and quarterly), respectively.

Table 2-21. Summary of the Model Plant Cost of Control for Biennial OGI Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with savings)[b] ($/ton)	
	Methane	VOC	Methane	VOC
Single Pollutant Approach				
Low Production Well Site Program	$1,685	$6,062	$1,487	$5,349
Multi-pollutant Approach				
Low Production Well Site Program	$843	$3,031	$744	$2,675

[a] The weighted average for the segments were calculated using the 2021 activity counts of 193 low production gas well sites, 1,017 low production oil well sites (GOR<300), and 569 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 2-22. 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	$1,432	$5,153	$1,234	$4,440
Low Production Well Site Program	$2,106	$7,578	$1,908	$6,865
Gathering & Boosting Station Program	$705	$2,698	$552	$1,985
Compressor Station Program (weighted average)	$704	$3,606	$572	$2,927
Multi-pollutant Approach				
Non-Low Production Well Site Program	$716	$2,577	$617	$2,220
Low Production Well Site Program	$1,053	$3,789	$954	$3,433
Gathering & Boosting Station Program	$375	$1,349	$276	$992
Compressor Station Program (weighted average)	$352	$1,803	$286	$1,463

[a.] The weighted average for the segments were calculated using the 2021 activity counts of 1,257 non-low production gas well sites, 1,401 non-low production oil well sites (GOR<300), 5,697 non-low production oil well sites (GOR>300), 193 low production gas well sites, 1,017 low production oil well sites (GOR<300), 569 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 2-23. Summary of the Model Plant Cost of Control for Semiannual OGI Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with savings)[b] ($/ton)	
	Methane	VOC	Methane	VOC
Single Pollutant Approach				
Non-Low Production Well Site Program	$1,202	$4,324	$1,004	$3,611
Low Production Well Site Program	$1,700	$6,116	$1,502	$5,403
Gathering & Boosting Station Program	$732	$2,632	$533	$1,919
Compressor Station Program (weighted average)	$653	$3,341	$520	$2,662
Multi-pollutant Approach				
Non-Low Production Well Site Program	$601	$2,162	$502	$1,806
Low Production Well Site Program	$850	$3,058	$751	$2,702
Gathering & Boosting Station Program	$366	$1,316	$267	$960
Compressor Station Program (weighted average)	$326	$1,671	$260	$1,331

[a.] The weighted average for the segments were calculated using the 2021 activity counts of 1,257 non-low production gas well sites, 1,401 non-low production oil well sites (GOR<300), 5,697 non-low production oil well sites (GOR>300), 193 low production gas well sites, 1,017 low production oil well sites (GOR<300), 569 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 2-24. Summary of the Model Plant Cost of Control for Quarterly OGI Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with savings)[b] ($/ton)	
	Methane	VOC	Methane	VOC
Single Pollutant Approach				
Non-Low Production Well Site Program	$1,313	$4,725	$1,115	$4,012
Gathering & Boosting Station Program	$895	$3,221	$697	$2,508
Compressor Station Program (weighted average)	$763	$3,908	$630	$3,228
Multi-pollutant Approach				
Non-Low Production Well Site Program	$657	$2,363	$558	$2,006
Gathering & Boosting Station Program	$448	$1,611	$349	$1,254
Compressor Station Program (weighted average)	$382	$1,954	$315	$1,614

[a.] The weighted average for the segments were calculated using the 2021 activity counts of 1,257 non-low production gas well sites, 1,401 non-low production oil well sites (GOR<300), 5,697 non-low production oil well sites (GOR>300), 212 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.

2.4.1.3 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[68] 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 oxides (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.

2.4.2 Fugitive Emissions Detection and Repair with Method 21

The 2016 NSPS OOOOa 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 plan, surveys using Method 21 instrumentation, resurveys 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. The EPA's analysis 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 are assumed to vary based on the frequency of monitoring and the instrument reading that triggers repair.

2.4.2.1 Method 21 Emission Reduction Potential

As stated in Section 2.4.1.1, we received comments asserting that the EPA inappropriately used Method 21 effectiveness estimates based on SOCMI. In response to these comments, we have updated the Method 21 effectiveness estimates using information for the oil and gas industry. We used the same methodology used in 2016 to determine the Method 21 effectiveness but applied the average leak rates

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[68] 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.*

and emissions factors that are specific to the oil and gas industry. The full methodology used to determined the Method 21 emission reduction potential is described below.

The EPA based the emission reduction analysis on the method for estimating LDAR control effectiveness from Chapter 5.3.1 of the Protocol for Equipment Leak Emission Estimates (EPA-453/R-95-017).[69] 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. The equations for these leak rates at various leak definitions are provided in the EPA Protocol for SOCMI, petroleum refineries, marketing terminals, and oil and gas production. The variable for determining the leak rate from these equations is the leak fraction. To determine the leak fraction, the stepwise approach was used to estimate the leak frequency immediately after and immediately preceding a monitoring cycle. The equations for determining these values are shown in the equations below.

$$Y_i = Z_i - (FR - Z_i) + (FR * Z_i * R)$$

where:

Yi = Leak fraction immediately after monitoring cycle i;

Zi = Leak fraction immediately after monitoring cycle i (Note that Z1 equals the initial leak frequency);

R = Fraction of repaired components for which a leak immediately recurs; and

FR = Fraction of leaking components successfully repaired.

$$Z_{i+1} = O_c * (1 - Y_i) + Y_I$$

where:

Zi*1 = Leak fraction immediately preceding monitoring cycle i+1;

Oc = Fraction of non-leaking components which will leak in the time period between monitoring cycles (e.g., occurrence rate); and

Yi = Leak fraction immediately after monitoring cycle i.

Other parameters included in the monitoring cycle calculations are the percentage of successfully repaired components, the percentage of new leaks, and the percentage of leaks that were repaired but have reoccurred. The 1995 Protocol does not provide these data for oil and natural gas production; only for the SOCMI and petroleum refineries. Sufficient data was also not provided by commenters using Method 21

[69] See US EPA, "1995 Protocol for Equipment Leak Emission Estimates Emission Standards" located at Docket ID No. EPA-HQ-OAR-2017-0483-0002.

to allow us to generate these values for the oil and gas industry. The petroleum 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, the EPA 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 for these specific parameters.

While the occurrence rates for SOCMI were included for monthly and quarterly monitoring (1.0 and 2.97, respectively), this information was calculated for the oil and gas production industry. The following equations were used to calculate the monthly and quarterly occurrence rates for valves in the oil and gas industry:

$$O_c = 0.0976 * (\mathrm{LF}) + 0.264$$

where:

Oc = Monthly occurrence rate for valves; and

LF = Initial leak fraction.

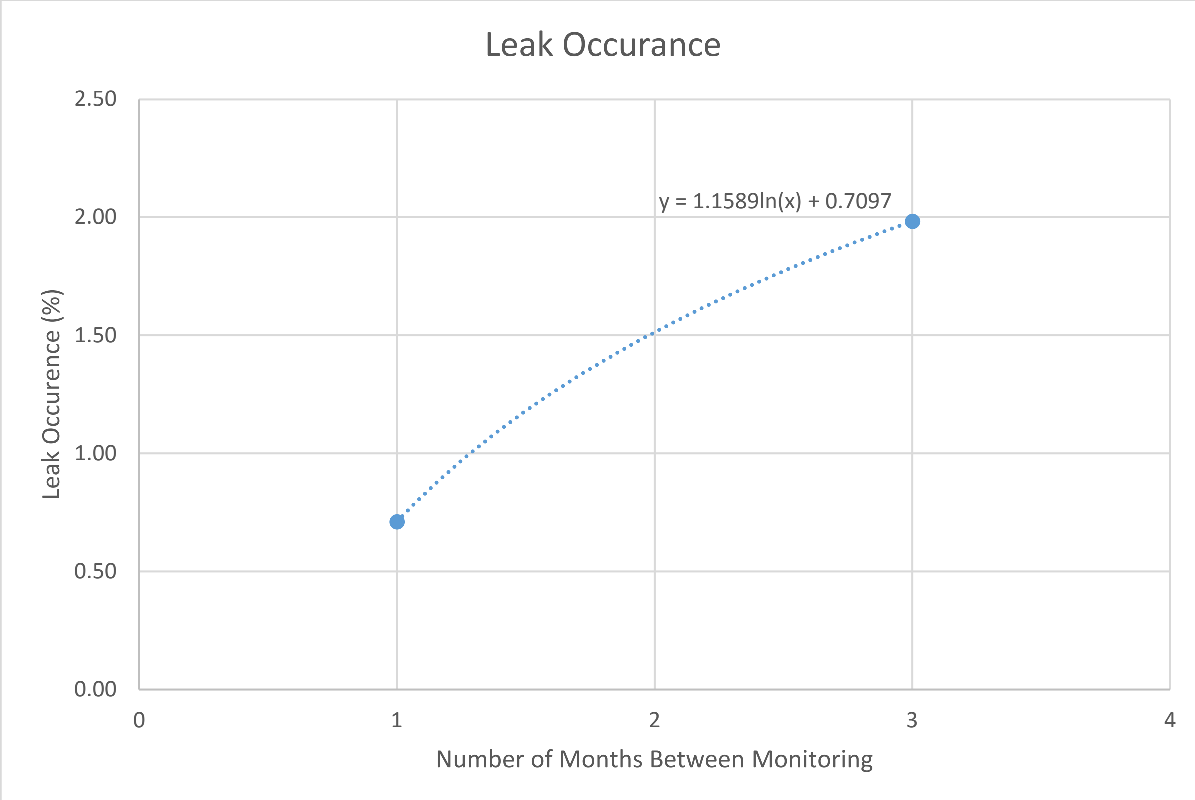
$$Q = M + M * (1 + M) + M * (1 - \left(M + M * (1 - M)\right))$$

where:

M = Monthly occurrence rate; and

Q = Quarterly occurrence rate.

To calculate the annual and semiannual occurrence rates, a logarithmic function was derived from the data points. Using this logarithmic function, the occurrence rates for semiannual and annual monitoring were estimated as provided in Table 2-24. A plot of the equation is shown below.



The initial leak fraction for the Method 21 monitoring program at oil and gas sites was calculated using the average leak equations in Table 5-7 of the EPA Protocol. Valves were selected because they represent the largest portion of fugitive emissions from oil and gas operations for non-storage vessel components, and would provide comparable emission reduction percentages for other components. Initial leak frequencies were calculated gas valves at 500 and 10,000 ppm screening values. The average leak fraction equation and calculated initial leak frequency are provided in Table 2-25.

Using the parameters in Table 2-25, 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 2-26.

Table 2-25. Parameters and Assumptions Used to Calculate Monitoring Cycles

Parameter	Parameter Value (500 ppm)	Parameter Value (10,000 ppm)
Occurrence Rate	5.79% Biennial 4.72% Annual 3.65% Semiannual 2.58% Quarterly	4.39% Biennial 3.59% Annual 2.79% Semiannual 1.98% Quarterly
Recurrence Rate	14%	14%
Unsuccessful Repair Rate	10%	10%
Initial Leak Frequency	6.42%	4.57%
Average Leak Rate Equation	ALR = (0.07*LF) + 9.1E-6	ALR = (0.098*LF) + 2.5E-5

Table 2-26. 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	25	30	30
Annual	38	42	40
Semiannual	52	55	60
Quarterly	65	68	80

Tables 2-27a, 2-27b, and 2-27c summarize the estimated model plant emission reductions for the alternative Method 21 monitoring and repair option for 500 and 10,000 ppm leak thresholds.

Table 2-27a. 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)		Method 21 500 ppm (tpy)	
	Methane	VOC	Methane	VOC	Methane	VOC
Annual Monitoring						
Gas Well Sites	2.36	0.66	2.25	0.62	2.48	0.69
Oil Well Sites (GOR < 300)	0.82	0.23	0.78	0.22	0.86	0.24
Oil Well Sites (GOR > 300)	1.22	0.34	1.16	0.32	1.28	0.35
Low Production Gas Well Sites	1.39	0.387	1.32	0.37	1.46	0.41
Low Production Oil Well Sites (GOR < 300)	0.62	0.171	0.59	0.16	0.65	0.18
Low Production Oil Well Sites (GOR > 300)	0.82	0.227	1.16	0.32	1.28	0.35
Semiannual Monitoring						
Gas Well Sites	3.55	0.99	3.07	0.85	3.25	0.90
Oil Well Sites (GOR < 300)	1.23	0.34	1.07	0.30	1.13	0.31
Oil Well Sites (GOR > 300)	1.82	0.51	1.58	0.44	1.67	0.46
Low Production Gas Well Sites	2.09	0.581	1.81	0.50	1.91	0.53
Low Production Oil Well Sites (GOR < 300)	0.92	0.257	0.80	0.22	0.85	0.24
Low Production Oil Well Sites (GOR > 300)	1.22	0.340	1.58	0.44	1.67	0.46
Quarterly Monitoring						
Gas Well Sites	4.73	1.315	3.84	1.07	4.02	1.12
Oil Well Sites (GOR < 300)	1.65	0.457	1.34	0.37	1.40	0.39
Oil Well Sites (GOR > 300)	2.43	0.676	1.98	0.55	2.07	0.57

Table 2-27b. 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	1.04	0.290	0.87	0.242	1.04	0.290
Low Production Oil Well Sites (GOR < 300)	0.46	0.128	0.38	0.107	0.46	0.128
Low Production Oil Well Sites (GOR > 300)	0.61	0.170	0.76	0.211	0.91	0.254

Table 2-27c. 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)		Method 21 500 ppm (tpy)	
	Methane	VOC	Methane	VOC	Methane	VOC
Annual Monitoring						
Gathering & Boosting	6.7	1.85	6.4	1.77	7.1	1.96
Transmission	16.2	0.45	15.4	0.43	17.1	0.47
Storage	57.0	1.58	54.4	1.51	60.4	1.67
Semiannual Monitoring						
Gathering & Boosting	10.0	2.8	8.6	2.39	9.2	2.56
Transmission	24.2	0.7	20.9	0.58	22.3	0.62
Storage	85.5	2.4	73.8	2.04	78.8	2.18
Quarterly Monitoring						
Gathering & Boosting	13.3	3.7	10.9	3.02	11.3	3.15
Transmission	32.3	0.9	26.4	0.73	27.5	0.76
Storage	114.0	3.2	93.2	2.58	97.1	2.69

2.4.2.2 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$):

- Reading of the rule and instructions would take 4 hours at a cost of $245.
- Development of a fugitive emission monitoring plan would take 60 hours and $3,672 for well sites, 25 hours and $1,530 for gathering and boosting stations, and 60 hours and $3,672 for transmission and storage.
- It was estimated that a Method 21 monitoring instrument costs $13,474[70] instrument and the data collection system costs $18,607.[71]
- 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 40 hours per person to complete a Method 21 survey at a cost of $2,448 for each monitoring event. For transmission stations, it was estimated to take 2 people a total of 50 hours per person to complete a Method 21 survey at a cost of $3,060 per monitoring event. For storage stations, it was estimated to take 2 people a total of 88 hours to complete a Method 21 survey at a cost of $5,386.[72]
- Annual repair costs were estimated to be $304 per monitoring event for well sites, $158 per monitoring event for low production well sites, $870 per monitoring event for gathering and boosting stations, $3,537 per monitoring event for transmission stations, and $7,014 per monitoring event for storage stations. These costs were estimated assuming 3 leaks for well sites where 2 leaks are fixed online and one leak is fixed offline).[73] For compressor stations, these costs were estimated assuming 11 leaks for gathering and boosting stations,[74] 24 leaks for transmission,[75] and 59 leaks for storage.[76] For all compressor station leaks, 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.

[70] Based on the cost of a data collection system per company of $10,500, adjusted to $2016 using an inflation factor of 1.28322 obtained from Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA. Analysis of Emissions Reduction Techniques for Equipment Leaks. December 21, 2011. EPA-HQ-OAR-2010-0869-0029.
[71] Based on the cost of a data collection system per company of $14,500, adjusted to $2016 using an inflation factor of 1.28322 obtained from Memorandum from Cindy Hancy, RTI International to Jodi Howard, EPA. Analysis of Emissions Reduction Techniques for Equipment Leaks. December 21, 2011. EPA-HQ-OAR-2010-0869-0029.
[72] Costs for contractor based OGI monitoring obtained from the Carbon Limits report.
[73] The leak percentage was obtained from Attachment B "API Analysis of Subpart OOOOa Semi-Annual Leak Survey Data" submitted by API to EPA in public comments. See Docket ID EPA-HQ-OAR-2017-0483-0801.
[74] The leak percentage was obtained from information submitted through public comments from GPA located at Docket ID. EPA-HQ-OAR-2017-0483-1261.
[75] The leak percentage was obtained from information submitted through Subpart W of the Greenhouse Gas Reporting Program.
[76] Id.

- Annual recordkeeping database maintenance and license fee was estimated at $469 for seminannual monitoring for well sites and $472 for quarterly monitoring for compressor stations.
- Additional recordkeeping and data management costs were estimated at $323 for seminannual monitoring for well sites and $645 for quarterly monitoring for compressor stations.
- Preparation of annual reports was estimated to take 1 person a total of 3 hours to complete at a cost of $184.

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, and the Method 21 monitoring instrument costs and the data collection system. The total capital cost of these activities at well sites was calculated to be $27,993 per company defined area. Assuming that each company owns and operates 22 well sites within a company defined area,[77] the capital cost per well site was estimated to be $1,272. For gathering and boosting compressor stations, the capital cost for reading the rule, development of fugitive emissions monitoring plan, and the Method 21 monitoring instrument costs and the data collection system was calculated to be $28,566, 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 $4,081. For transmission and storage stations, the capital cost per facility was calculated to be $30,708.

For all oil and natural gas segments, the annual cost includes Method 21 survey, cost of repair of fugitive emissions found, resurvey of repaired components, annual recordkeeping database maintenance and license fee, additional recordkeeping and data management costs, preparation and submittal of an annual report, and the amortized capital cost over 8 years at 7 percent interest. The EPA calculated the annual cost for biennial, annual, semiannual, and quarterly Method 21 surveys at well sites, and annual, semiannual, and quarterly Method 21 surveys at compressor stations.

The EPA used the same two methods (single pollutant and multi-pollutant) discussed in section 2.4.1.2 for the Method 21 program. Based on estimated emission reductions and the estimated cost for implementing a Method 21 fugitive emissions monitoring and repair program at the affected facilities, 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

[77] The number of well sites owned and operated by companies was calculated using data from the Fort Worth study. An analysis of additional information from 2017 compliance reports was consistent with the previously calculated number of well sites per company of 22.

control for all well sites and all compressor stations (*i.e.,* gathering and boosting, transmission and storage). Tables 2-28, 2-29, 2-30, and 2-31 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, and quarterly, respectively).

Table 2-28. Summary of the Model Plant Cost of Control for Biennial Method 21 Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with savings)[b] ($/ton)		Cost of Control (without savings) ($/ton)		Cost of Control (with savings)[b] ($/ton)	
	500 ppm				10,000 ppm			
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Single Pollutant Approach								
Low Production Well Site Program	$2,459	$8,846	$2,261	$8,133	$2,951	$10,615	$2,753	$9,902
Multi-pollutant Approach								
Low Production Well Site Program	$1,230	$4,423	$1,131	$4,067	$1,476	$5,308	$1,377	$4,951

[a.] The weighted average for the segments were calculated using the 2021 activity counts of 193 low production gas well sites, 1,107 low production oil well sites (GOR<300), 569 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 2-29. Summary of the Model Plant Cost of Control for Annual Method 21 Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with savings)[b] ($/ton)		Cost of Control (without savings) ($/ton)		Cost of Control (with savings)[b] ($/ton)	
	500 ppm				10,000 ppm			
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Single Pollutant Approach								
Non-Low Production Well Site Program	$1,824	$6,561	$1,626	$5,848	$2,016	$7,252	$1,818	$6,539
Low Production Well Site Program	$2,969	$10,680	$2,771	$9,967	$3,281	$11,804	$3,083	$11,091
Gathering & Boosting Station Program	$775	$2,790	$577	$2,077	$861	$3,096	$663	$2,383
Compressor Station Program (weighted average)	$763	$3,909	$631	$3,230	$847	$4,339	$715	$3,659
Multi-pollutant Approach								
Non-Low Production Well Site Program	$912	$3,281	$813	$2,924	$1,008	$3,626	$909	$3,270
Low Production Well Site Program	$1,485	$5,340	$1,386	$4,984	$1,641	$5,902	$1,542	$5,546
Gathering & Boosting Station Program	$388	$1,395	$289	$1,038	$430	$1,548	$331	$1,192
Compressor Station Program (weighted average)	$382	$1,955	$315	$1,615	$424	$2,170	$357	$1,830

[a.] The weighted average for the segments were calculated using the 2021 activity counts of 1,257 non-low production gas well sites, 1,401 non-low production oil well sites (GOR<300), 5,697 non-low production oil well sites (GOR>300), 193 low production gas well sites, 1,017 low production oil well sites (GOR<300), 569 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 2-30. Summary of the Model Plant Cost of Control for Semiannual Method 21 Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with savings)[b] ($/ton)		Cost of Control (without savings) ($/ton)		Cost of Control (with savings)[b] ($/ton)	
	500 ppm				10,000 ppm			
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Single Pollutant Approach								
Non-Low Production Well Site Program	$1,950	$7,015	$1,752	$6,302	$2,063	$7,420	$1,864	$6,707
Low Production Well Site Program	$3,216	$11,568	$3,017	$10,855	$3,401	$12,235	$3,203	$11,522
Gathering & Boosting Station Program	$862	$3,101	$664	$2,388	$920	$3,311	$722	$2,598
Compressor Station Program (weighted average)	$806	$4,128	$674	$3,449	$861	$4,407	$728	$3,728
Multi-pollutant Approach								
Non-Low Production Well Site Program	$975	$3,508	$876	$3,151	$1,032	$4,226	$932	$3,354
Low Production Well Site Program	$1,608	$5,784	$1,509	$5,428	$1,701	$6,118	$1,602	$5,761
Gathering & Boosting Station Program	$431	$1,551	$332	$1,194	$460	$1,655	$361	$1,299
Compressor Station Program (weighted average)	$403	$2,064	$337	$1,724	$430	$2,204	$364	$1,864

a. The weighted average for the segments were calculated using the 2021 activity counts of 1,257 non-low production gas well sites, 1,401 non-low production oil well sites (GOR<300), 5,697 non-low production oil well sites (GOR>300), 193 low production gas well sites, 1,017 low production oil well sites (GOR<300), 569 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 2-31. Summary of the Model Plant Cost of Control for Quarterly Method 21 Monitoring Option

Model Plant[a]	Cost of Control (without savings) ($/ton)		Cost of Control (with savings)[b] ($/ton)		Cost of Control (without savings) ($/ton)		Cost of Control (with savings)[b] ($/ton)	
	500 ppm				10,000 ppm			
	Methane	VOC	Methane	VOC	Methane	VOC	Methane	VOC
Single Pollutant Approach								
Non-Low Production Well Site Program	$2,528	$9,093	$2,329	$8,380	$2,644	$9,512	$2,446	$8,799
Gathering & Boosting Station Program	$1,132	$4,072	$934	$3,359	$1,180	$4,246	$982	$3,533
Compressor Station Program (weighted average)	$1,011	$5,177	$878	$4,497	$1,054	$5,399	$922	$4,719
Multi-pollutant Approach								
Non-Low Production Well Site Program	$1,264	$4,547	$1,165	$4,190	$1,322	$4,756	$1,223	$4,400
Gathering & Boosting Station Program	$566	$2,036	$467	$1,679	$590	$2,123	$491	$1,766
Compressor Station Program (weighted average)	$506	$2,589	$439	$2,249	$527	$2,699	$461	$2,360

[a.] The weighted average for the segments were calculated using the 2021 activity counts of 1,257 non-low production gas well sites, 1,401 non-low production oil well sites (GOR<300), 5,697 non-low production oil well sites (GOR>300), 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.

2.4.2.3 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 2.4.1.3 for OGI. The EPA assumes the same mobile emissions from the Method 21 program.

2.5 Regulatory Options

As discussed in Section 2.4, the EPA continues 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, the EPA evaluated the following regulatory options for 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 at well sites and compressor stations.
  - 1c. Monitoring on a quarterly frequency at well sites and compressor stations.
  - 1d. 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 at well sites and compressor stations.
  - 2c. Monitoring on a quarterly frequency at compressor stations.
  - 2d. 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 at well sites and compressor stations.
  - 3c. Monitoring on a quarterly frequency at well sites and compressor stations.
  - 3d. Monitoring on a biennial frequency at low production well sites.

2.5.1 Evaluation of Regulatory Options for Fugitive Emissions

As noted above, 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).

2.5.1.1 Option 1 – OGI Monitoring

Non-Low Production Well Sites. For non-low production well sites, the EPA developed 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 $1,432 per ton of methane reduced, and $1,234 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is

$5,153 per ton of VOC reduced, and $4,440 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on annual monitoring is $2,577 per ton VOC reduced, and $2,220 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multi-pollutant approach is $716 per ton methane reduced, and $617 per ton if natural gas savings are considered.

Under semiannual monitoring (Option 1b) 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 $1,202 per ton of methane reduced, and $1,004 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,324 per ton of VOC reduced, and $3,611 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on semiannual monitoring is $2,162 per ton VOC reduced, and $1,806 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multi-pollutant approach is $601 per ton methane reduced, and $502 per ton if natural gas savings are considered.

Finally, for quarterly 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 $1,313 per ton of methane reduced, and $1,115 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,725 per ton of VOC reduced, and $4,012 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on quarterly monitoring is $2,363 per ton VOC reduced, and $2,006 per ton if natural gas savings are considered. The control cost for methane based on quarterly monitoring under the multi-pollutant approach is $657 per ton methane reduced, and $558 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 $2,106 per ton of methane reduced, and $1,908 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $7,578 per ton of VOC reduced, and $6,865 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on annual monitoring is $3,789 per ton VOC reduced, and $3,433 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multi-pollutant approach is $1,053 per ton methane reduced, and $954 per ton if natural gas savings are considered.

Under the single pollutant approach for the semiannual monitoring frequency (Option 1b), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,700 per ton of methane reduced, and $1,502 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $6,116 per ton of VOC reduced, and $5,403 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on semiannual monitoring is $3,058 per ton VOC reduced, and $2,702 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multi-pollutant approach is $850 per ton methane reduced, and $751 per ton if natural gas savings are considered.

Finally for the biennial monitoring (Option 1d), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,685 per ton of methane reduced, and $1,487 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $6,062 per ton of VOC reduced, and $5,349 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on biennial monitoring is $3,031 per ton VOC reduced, and $2,675 per ton if natural gas savings are considered. The control cost for methane based on biennial monitoring under the multi-pollutant approach is $843 per ton methane reduced, and $744 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 $9,204 per ton of methane reduced, and $7,930 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $33,111 per ton of VOC reduced, and $28,530 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on annual monitoring is $16,556 per ton VOC reduced, and $14,265 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multi-pollutant approach is $4,602 per ton methane reduced, and $3,965 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.

Gathering and Boosting Compressor Stations. For gathering and boosting 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 $750 per ton of methane reduced, and $552 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $2,698 per ton of VOC reduced, and $1,985 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on annual monitoring is $1,349 per ton VOC reduced, and $992 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multi-pollutant approach is $375 per ton methane reduced, and $276 per ton if natural gas savings are considered.

Under the single pollutant approach for semiannual monitoring (Option 1b), if all costs are assigned to methane and zero to VOC reductions, the cost is $732 per ton of methane reduced, and $533 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $2,632 per ton of VOC reduced, and $1,919 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on semiannual monitoring is $1,316 per ton VOC reduced, and $960 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multi-pollutant approach is $366 per ton methane reduced, and $267 per ton if natural gas savings are considered.

Finally, for quarterly monitoring (Option 1c), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $895 per ton of methane reduced, and $697 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,221 per ton of VOC reduced, and $2,508 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on quarterly monitoring is $1,611 per ton VOC reduced, and $1,254 per ton if natural gas savings are considered. The control cost for methane based on quarterly monitoring under the multi-pollutant approach is $448 per ton methane reduced, and $349 per ton if natural gas savings are considered.

Compressor Stations. For compressor stations under a weighted average (considering all 3 types), 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 $704 per ton of methane reduced, and $572 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,606 per ton of VOC reduced, and $2,927 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on annual monitoring is $1,803 per ton VOC reduced, and $1,463 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multi-pollutant approach is $352 per ton methane reduced, and $286 per ton if natural gas savings are considered.

Under the single pollutant approach for semiannual monitoring (Option 1b), if all costs are assigned to methane and zero to VOC reductions, the cost is $653 per ton of methane reduced, and $520 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,341 per ton of VOC reduced, and $2,662 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on semiannual monitoring is $1,671 per ton VOC reduced, and $1,331 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multi-pollutant approach is $326 per ton methane reduced, and $260 per ton if natural gas savings are considered.

Finally, for quarterly monitoring (Option 1c), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $763 per ton of methane reduced, and $630 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,908 per ton of VOC reduced, and $3,228 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on quarterly monitoring is $1,954 per ton VOC reduced, and $1,614 per ton if natural gas savings are considered. The control cost for methane based on quarterly monitoring under the multi-pollutant approach is $382 per ton methane reduced, and $315 per ton if natural gas savings are considered.

Because the gas handled by transmission and storage facilities is not typically owned by these facilities, the value of the gas saved as an offset to the cost is not considered. However, for gathering and boosting stations, the gas savings could be considered. Therefore, the cost of control for compressor stations considering the gas savings contributed by gathering and boosting stations is calculated. This cost savings is reflected in the cost presented above and summarized in Table 2-32.

Table 2-32. 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	$1,432	$5,153	$716	$2,577	$1,234	$4,440	$617	$2,220
1b – Semiannual	$1,202	$4,324	$601	$2,162	$1,004	$3,611	$502	$1,806
1c – Quarterly	$1,313	$4,725	$657	$2,363	$1,115	$4,012	$558	$2,006
Low Production Well Sites								
1a – Annual	$2,106	$7,578	$1,053	$3,789	$1,908	$6,865	$954	$3,433
1b – Semiannual	$1,700	$6,116	$850	$3,058	$1,502	$5,403	$751	$2,702
1d – Biennial	$1,685	$6,062	$843	$3,031	$1,487	$5,349	$744	$2,675
Wellhead Only Well Sites								
1a – Annual	$9,204	$33,111	$4,602	$16,556	$7,930	$28,530	$3,965	$14,265
Gathering & Boosting Compressor Stations								
1a – Annual	$750	$2,698	$375	$1,349	$552	$1,985	$276	$992
1b – Semiannual	$732	$2,632	$366	$1,316	$533	$1,919	$267	$960
1c – Quarterly	$895	$3,221	$448	$1,611	$697	$2,508	$349	$1,254
Compressor Stations (weighted average)								
1a – Annual	$704	$3,606	$352	$1,803	$572	$2,927	$286	$1,463
1b – Semiannual	$653	$3,341	$326	$1,671	$520	$2,662	$260	$1,331
1c – Quarterly	$763	$3,908	$382	$1,954	$630	$3,228	$315	$1,614

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 $1,824 per ton of methane reduced, and $1,626 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $6,561 per ton of VOC reduced, and $5,848 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on annual monitoring is $3,281 per ton VOC reduced, and $2,924 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multi-pollutant approach is $912 per ton methane reduced, and $813 per ton if natural gas savings are considered.

Under the single pollutant approach for the semiannual monitoring frequency (Option 2b), if all costs are assigned to methane and zero to VOC reductions, the cost is $1,950 per ton of methane reduced, and $1,752 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $7,015 per ton of VOC reduced, and $6,302 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on semiannual monitoring is $3,508 per ton VOC reduced, and $3,151 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multi-pollutant approach is $975 per ton methane reduced, and $876 per ton if natural gas savings are considered.

Finally, for quarterly 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 $2,528 per ton of methane reduced, and $2,329 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $9,093 per ton of VOC reduced, and $8,380 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on quarterly monitoring is $4,546 per ton VOC reduced, and $4,190 per ton if natural gas savings are considered. The control cost for methane based on quarterly monitoring under the multi-pollutant approach is $1,264 per ton methane reduced, and $1,165 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 $2,969 per ton of methane reduced, and $2,771 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $10,680 per ton of VOC reduced, and $9,967 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on annual monitoring is $5,340 per ton VOC reduced, and $4,984 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multi-pollutant approach is $1,485 per ton methane reduced, and $1,386 per ton if natural gas savings are considered.

Under the single pollutant approach for the semiannual monitoring frequency (Option 2b), if all costs are assigned to methane and zero to VOC reductions, the cost is $3,216 per ton of methane reduced, and $3,016 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $11,568 per ton of VOC reduced, and $10,855 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on semiannual monitoring is $5,784 per ton VOC reduced, and $5,427 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multi-pollutant approach is $1,608 per ton methane reduced, and $1,508 per ton if natural gas savings are considered.

For biennial monitoring (Option 2d), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $2,459 per ton of methane reduced, and $2,261 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $8,846 per ton of VOC reduced, and $8,133 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on biennnial monitoring is $4,423 per ton VOC reduced, and $4,066 per ton if natural gas savings are considered. The control cost for methane based on biennial monitoring under the multi-pollutant approach is $1,230 per ton methane reduced, and $1,130 per ton if natural gas savings are considered.

Gathering and Boosting Compressor Stations. For gathering and boosting 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 $775 per ton of methane reduced, and $577 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $2,790 per ton of VOC reduced, and $2,077 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on annual monitoring is $1,395 per ton VOC reduced, and $1,038 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multi-pollutant approach is $388 per ton methane reduced, and $289 per ton if natural gas savings are considered.

Under the single pollutant approach for semiannual monitoring (Option 2b), if all costs are assigned to methane and zero to VOC reductions, the cost is $862 per ton of methane reduced, and $664 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,101 per ton of VOC reduced, and $2,388 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on semiannual monitoring is $1,551 per ton VOC reduced, and $1,194 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multi-pollutant approach is $431 per ton methane reduced, and $332 per ton if natural gas savings are considered.

Finally for quarterly monitoring (Option 2c), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,132 per ton of methane reduced, and $934 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,072 per ton of VOC reduced, and $3,359 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on quarterly monitoring is $2,036 per ton VOC reduced, and $1,679 per ton if natural gas savings are considered. The control cost for methane based on quarterly monitoring under the multi-pollutant approach is $566 per ton methane reduced, and $467 per ton if natural gas savings are considered.

Compressor Stations. For compressor stations under a weighted average (considering all 3 types), 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 $763 per ton of methane reduced, and $631 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,909 per ton of VOC reduced, and $3,230 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on annual monitoring is $1,955 per ton VOC reduced, and $1,615 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multi-pollutant approach is $382 per ton methane reduced, and $315 per ton if natural gas savings are considered.

Under the single pollutant approach for semiannual monitoring (Option 2b), if all costs are assigned to methane and zero to VOC reductions, the cost is $806 per ton of methane reduced, and $674 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,128 per ton of VOC reduced, and $3,449 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on semiannual monitoring is $2,064 per ton VOC reduced, and $1,724 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multi-pollutant approach is $403 per ton methane reduced, and $337 per ton if natural gas savings are considered.

Finally for quarterly monitoring (Option 2c), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,011 per ton of methane reduced, and $878 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $5,177 per ton of VOC reduced, and $4,497 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on quarterly monitoring is $2,589 per ton VOC reduced, and $2,249 per ton if natural gas savings are considered. The control cost for methane based on quarterly monitoring under the multi-pollutant approach is $506 per ton methane reduced, and $439 per ton if natural gas savings are considered.

Because the gas handled by transmission and storage facilities is not typically owned by these facilities, the value of the gas saved as an offset to the cost is not considered. However, for gathering and boosting stations, the gas savings could be considered. Therefore, the cost of control for compressor stations considering the gas savings contributed by gathering and boosting stations is calculated. This cost savings is reflected in the cost presented above and summarized in Table 2-33.

Table 2-33. 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	$1,824	$6,561	$912	$3,281	$1,626	$5,848	$813	$2,924
2b - Semiannual	$1,950	$7,015	$975	$3,508	$1,752	$6,302	$876	$3,151
2c - Quarterly	$2,528	$9,093	$1,264	$4,546	$2,329	$8,380	$1,165	$4,190
Low Production Well Sites								
2a - Annual	$2,969	$10,680	$1,485	$5,340	$2,771	$9,967	$1,386	$4,984
2b - Semiannual	$3,216	$11,568	$1,608	$5,784	$3,016	$10,855	$1,508	$5,427
2d - Biennial	$2,459	$8,846	$1,230	$4,423	$2,261	$8,133	$1,130	$4,066
Gathering & Boosting Compressor Stations								
2a - Annual	$775	$2,790	$388	$1,395	$577	$2077	$289	$1,038
2b - Semiannual	$862	$3,101	$431	$1,551	$664	$2,388	$332	$1,194
2c - Quarterly	$1,132	$4,072	$566	$2,036	$934	$3,359	$467	$1,679
Compressor Stations (weighted average)								
2a - Annual	$763	$3,909	$382	$1,955	$631	$3,230	$315	$1,615
2b - Semiannual	$806	$4,128	$403	$2,064	$674	$3,449	$337	$1,724
2c - Quarterly	$1,011	$5,177	$506	$2,589	$878	$4,497	$439	$2,249

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 $2,016 per ton of methane reduced, and $1,818 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to

VOC reduction, the cost is $7,252 per ton of VOC reduced, and $6,539 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on annual monitoring is $3,626 per ton VOC reduced, and $3,270 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multi-pollutant approach is $1,008 per ton methane reduced, and $909 per ton if natural gas savings are considered.

Under the single pollutant approach for the semiannual monitoring frequency (Option 3b), if all costs are assigned to methane and zero to VOC reductions, the cost is $2,063 per ton of methane reduced, and $1,864 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $7,420 per ton of VOC reduced, and $6,707 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on semiannual monitoring is $3,710 per ton VOC reduced, and $3,354 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multi-pollutant approach is $1,031 per ton methane reduced, and $932 per ton if natural gas savings are considered.

Finally, for quarterly 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 $2,644 per ton of methane reduced, and $2,446 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $9,512 per ton of VOC reduced, and $8,799 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on quarterly monitoring is $4,756 per ton VOC reduced, and $4,400 per ton if natural gas savings are considered. The control cost for methane based on quarterly monitoring under the multi-pollutant approach is $1,322 per ton methane reduced, and $1,223 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 $3,281 per ton of methane reduced, and $3,083 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $11,804 per ton of VOC reduced, and $11,091 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on annual monitoring is $5,902 per ton VOC reduced, and $5,546 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multi-pollutant approach is $1,641 per ton methane reduced, and $1,542 per ton if natural gas savings are considered.

Under the single pollutant approach for the semiannual monitoring frequency (Option 3b), if all costs are assigned to methane and zero to VOC reductions, the cost is $3,401 per ton of methane reduced, and $3,203 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $12,235 per ton of VOC reduced, and $11,522 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on semiannual monitoring is $6,118 per ton VOC reduced, and $5,761 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multi-pollutant approach is $1,701 per ton methane reduced, and $1,601 per ton if natural gas savings are considered.

Finally for the biennial monitoring (Option 3d), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $2,951 per ton of methane reduced, and $2,753 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $10,615 per ton of VOC reduced, and $9,902 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on biennial monitoring is $5,308 per ton VOC reduced, and $4,951 per ton if natural gas savings are considered. The control cost for methane based on biennial monitoring under the multi-pollutant approach is $1,475 per ton methane reduced, and $1,376 per ton if natural gas savings are considered.

Gathering and Boosting Compressor Stations. For gathering and boosting compressor stations under a weighted average (considering all 3 types), 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 $861 per ton of methane reduced, and $663 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,096 per ton of VOC reduced, and $2,383 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on annual monitoring is $1,548 per ton VOC reduced, and $1,192 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multi-pollutant approach is $430 per ton methane reduced, and $331 per ton if natural gas savings are considered.

Under the single pollutant approach for semiannual monitoring (Option 3b), if all costs are assigned to methane and zero to VOC reductions, the cost is $920 per ton of methane reduced, and $722 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $3,311 per ton of VOC reduced, and $2,598 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on semiannual monitoring is $1,655 per ton VOC reduced, and $1,299 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multi-pollutant approach is $460 per ton methane reduced, and $361 per ton if natural gas savings are considered.

Finally for quarterly monitoring (Option 3c), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,180 per ton of methane reduced, and $982 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,246 per ton of VOC reduced, and $3,533 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on quarterly monitoring is $2,123 per ton VOC reduced, and $1,766 per ton if natural gas savings are considered. The control cost for methane based on quarterly monitoring under the multi-pollutant approach is $590 per ton methane reduced, and $491 per ton if natural gas savings are considered.

Compressor Stations. For compressor stations under a weighted average (considering all 3 types), 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 $847 per ton of methane reduced, and $715 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,339 per ton of VOC reduced, and $3,659 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on annual monitoring is $2,170 per ton VOC reduced, and $1,830 per ton if natural gas savings are considered. The control cost for methane based on annual monitoring under the multi-pollutant approach is $424 per ton methane reduced, and $357 per ton if natural gas savings are considered.

Under the single pollutant approach for semiannual monitoring (Option 3b), if all costs are assigned to methane and zero to VOC reductions, the cost is $861 per ton of methane reduced, and $728 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $4,407 per ton of VOC reduced, and $3,728 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on semiannual monitoring is $2,204 per ton VOC reduced, and $1,864 per ton if natural gas savings are considered. The control cost for methane based on semiannual monitoring under the multi-pollutant approach is $430 per ton methane reduced, and $364 per ton if natural gas savings are considered.

Finally for quarterly monitoring (Option 3c), under the single pollutant approach, if all costs are assigned to methane and zero to VOC reductions, the cost is $1,054 per ton of methane reduced, and $922 per ton if savings of the natural gas recovered is considered. Likewise, if all costs are assigned to VOC reduction, the cost is $5,399 per ton of VOC reduced, and $4,719 per ton of VOC reduced if savings of the natural gas recovered is considered. Under the multi-pollutant approach, the control cost for VOC based on quarterly monitoring is $2,699 per ton VOC reduced, and $2,360 per ton if natural gas savings are considered. The control cost for methane based on quarterly monitoring under the multi-pollutant approach is $527 per ton methane reduced, and $461 per ton if natural gas savings are considered.

Because the gas handled by transmission and storage facilities is not typically owned by these facilities, the value of the gas saved as an offset to the cost is not considered. However, for gathering and boosting stations, the gas savings could be considered. Therefore, the cost of control for compressor stations considering the gas savings contributed by gathering and boosting stations is calculated. This cost savings is reflected in the cost presented above and summarized in Table 2-34.

Table 2-34. 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	$2,016	$7,252	$1,008	$3,626	$1,818	$6,539	$909	$3,270
3b - Semiannual	$2,063	$7,420	$1,031	$3,710	$1,864	$6,707	$932	$3,354
3c - Quarterly	$2,644	$9,512	$1,322	$4,756	$2,446	$8,799	$1,223	$4,400
Low Production Well Sites								
3a - Annual	$3,281	$11,804	$1,641	$5,902	$3,083	$11,091	$1,542	$5,546
3b - Semiannual	$3,401	$12,235	$1,701	$6,118	$3,203	$11,522	$1,601	$5,761
3d - Biennial	$2,951	$10,615	$1,475	$5,308	$2,753	$9,902	$1,376	$4,951
Gathering & Boosting Compressor Stations								
3a - Annual	$847	$4,339	$424	$2,170	$715	$3,659	$357	$1,830
3b - Semiannual	$861	$4,407	$430	$2,204	$728	$3,728	$364	$1,864
3c - Quarterly	$1,054	$5,399	$527	$2,699	$922	$4,719	$461	$2,360
Compressor Stations (weighted average)								
3a - Annual	$861	$3,096	$430	$1,548	$663	$2,383	$331	$1,192
3b - Semiannual	$920	$3,311	$460	$1,655	$722	$2,598	$361	$1,299
3c - Quarterly	$1,180	$4,246	$590	$2,123	$982	$3,533	$491	$1,766

2.5.2 Incremental Cost

Another way to consider the cost of control is to examine the additional cost incurred to achieve any additional emission reductions between options. While the cost of control presented in Section 2.5.1 provides an overall average cost of control when comparing each individual option against a baseline of no fugitive emissions monitoring, it does not provide much insight into the incremental cost between options. The incremental cost of control provides insight into how much it costs to achieve the next increment of emission reductions going from one stringency level to the next, more stringent level. The EPA performed an analysis to understand the incremental cost of control for the increasing monitoring frequencies between options of an OGI-based fugitive emissions monitoring program. This information is presented at a nationwide level using the predicted number of sources subject to the requirements that are described in Section 3 of this document.

The following tables summarize the total and incremental cost of control for the various monitoring frequencies evaluated for non-low production well sites (Tables 2-35a and 2-35b), low production well sites (Tables 2-35c and 2-35d), gathering and boosting compressor stations (Tables 2-35e and 2-35f) and compressor stations weighted average (Tables 2-35g and 2-35h) for the year 2025. The incremental cost of control estimates are presented in the attached spreadsheets for OGI monitoring at well sites and compressor stations for the years 2019 through 2025. This information reflects the nationwide projections which are discussed in the Regulatory Impacts Analysis (RIA) for this final rule.

For each type of model plant, methane and VOC incremental cost of control are presented under the single pollutant approach only (*i.e.*, where all costs are applied to one pollutant and zero cost to the other). The capital costs are based on the total number of new sources projected to become subject to the requirements in that year. The annualized costs are cumulative, and are based on the total number of sources subject to the rule that year (including newly subject facilities and those already subject to the requirements from previous years).

Table 2-35a. Summary of Cost of Methane Control for Non-Low Production Well Sites, 2025

					Without Savings			With Savings		
Option	**Methane Emissions (tpy)**	**Cummulative Emission Reduction (tpy)**	**Incremental Emission Reduction (tpy)**	**Capital Cost ($)**	**Annualized Cost ($/yr)**	**Total Cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**	**Annualized Cost ($/yr)**	**Total Cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**
No Fugitive Monitoring	283,995									
1a Annual	170,397	113,598		$8,991,392	$162,723,571	$1,432		$140,208,821	$1,234	
1b Semiannual	113,598	170,397	56,799	$8,991,392	$204,808,269	$1,202	$741	$171,036,144	$1,004	$543
1c Quarterly	56,799	227,196	56,799	$8,991,392	$298,383,223	$1,313	$1,647	$253,353,723	$1,115	$1,449

Table 2-35b. Summary of Cost of VOC Control for Non-Low Production Well Sites, 2025

					Without Savings			With Savings		
Option	**VOC Emissions (tpy)**	**Cummulative Emission Reduction (tpy)**	**Incremental Emission Reduction (tpy)**	**Capital Cost ($)**	**Annualized Cost ($/yr)**	**Total Cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**	**Annualized Cost ($/yr)**	**Total Cost Effectiveness ($/ton)**	**Incremental Cost Effectiveness ($/ton)**
No Fugitive Monitoring	78,943									
1a Annual	47,366	31,577		$8,991,392	$162,723,571	$5,153		$140,208,821	$4,440	
1b Semiannual	31,577	47,366	15,789	$8,991,392	$204,808,269	$4,324	$2,665	$171,036,144	$3,611	$1,952
1c Quarterly	15,789	63,155	15,789	$8,991,392	$298,383,223	$4,725	$5,927	$253,353,723	$4,012	$5,214

Table 2-35c. Summary of Cost of Methane Control for Low Production Well Sites, 2025

Option	Methane Emissions (tpy)	Cummulative Emission Reduction (tpy)	Incremental Emission Reduction (tpy)	Capital Cost ($)	Without Savings: Annualized Cost ($/yr)	Without Savings: Total Cost Effectiveness ($/ton)	Without Savings: Incremental Cost Effectiveness ($/ton)	With Savings: Annualized Cost ($/yr)	With Savings: Total Cost Effectiveness ($/ton)	With Savings: Incremental Cost Effectiveness ($/ton)
No Fugitive Monitoring	34,955									
1d Biennial	24,468	10,486		$1,916,008	$17,669,592	$1,685		$15,591,206	$1,487	
1a Annual	20,973	13,982	3,495	$1,916,008	$29,451,910	$2,106	$3,371	$26,680,729	$1,908	$3,173
1b Semiannual	13,982	20,973	6,991	$1,916,008	$35,656,084	$1,700	$887	$31,499,312	$1,502	$689

Table 2-35d. Summary of Cost of VOC Control for Low Production Well Sites, 2025

Option	VOC Emissions (tpy)	Cummulative Emission Reduction (tpy)	Incremental Emission Reduction (tpy)	Capital Cost ($)	Without Savings: Annualized Cost ($/yr)	Without Savings: Total Cost Effectiveness ($/ton)	Without Savings: Incremental Cost Effectiveness ($/ton)	With Savings: Annualized Cost ($/yr)	With Savings: Total Cost Effectiveness ($/ton)	With Savings: Incremental Cost Effectiveness ($/ton)
No Fugitive Monitoring	9,717									
1d Biennial	6,802	2,915		$1,916,008	$17,669,592	$6,062		$15,591,206	$5,349	
1a Annual	5,830	3,887	972	$1,916,008	$29,451,910	$7,578	$12,126	$26,680,729	$6,865	$11,413
1b Semiannual	3,887	5,830	1,943	$1,916,008	$35,656,084	$6,116	$3,193	$31,499,312	$5,403	$2,480

Table 2-35e. Summary of Cost of Methane Control for Gathering & Boosting Compressor Stations, 2025

Option	Methane Emissions (tpy)	Cummulative Emission Reduction (tpy)	Incremental Emission Reduction (tpy)	Capital Cost ($)	Without Savings: Annualized Cost ($/yr)	Without Savings: Total Cost Effectiveness ($/ton)	Without Savings: Incremental Cost Effectiveness ($/ton)	With Savings: Annualized Cost ($/yr)	With Savings: Total Cost Effectiveness ($/ton)	With Savings: Incremental Cost Effectiveness ($/ton)
No Fugitive Monitoring	38,786									
1a Annual	23,272	15,514		$617,273	$11,633,844	$750		$8,558,951	$552	
1b Semiannual	15,514	23,272	7,757	$617,273	$17,026,594	$732	$695	$12,414,254	$533	$497
1c Quarterly	7,757	31,029	7,757	$617,273	$27,782,944	$895	$1,387	$21,633,158	$697	$1,188

Table 2-35f. Summary of Cost of VOC Control for Gathering & Boosting Compressor Stations, 2025

Option	VOC Emissions (tpy)	Cummulative Emission Reduction (tpy)	Incremental Emission Reduction (tpy)	Capital Cost ($)	Without Savings: Annualized Cost ($/yr)	Without Savings: Total Cost Effectiveness ($/ton)	Without Savings: Incremental Cost Effectiveness ($/ton)	With Savings: Annualized Cost ($/yr)	With Savings: Total Cost Effectiveness ($/ton)	With Savings: Incremental Cost Effectiveness ($/ton)
No Fugitive Monitoring	10,781									
1a Annual	6,469	4,313		$617,273	$11,633,844	$2,698		$8,558,951	$1,985	
1b Semiannual	4,313	6,469	2,156	$617,273	$17,026,594	$2,632	$2,501	$12,414,254	$1,919	$1,788
1c Quarterly	2,156	8,625	2,156	$617,273	$27,782,944	$3,221	$4,988	$21,633,158	$2,508	$4,275

Table 2-35g. Summary of Cost of Methane Control for Compressor Stations, 2025

Option	Methane Emissions (tpy)	Cummulative Emission Reduction (tpy)	Incremental Emission Reduction (tpy)	Capital Cost ($)	Without Savings: Annualized Cost ($/yr)	Without Savings: Total Cost Effectiveness ($/ton)	Without Savings: Incremental Cost Effectiveness ($/ton)	With Savings: Annualized Cost ($/yr)	With Savings: Total Cost Effectiveness ($/ton)	With Savings: Incremental Cost Effectiveness ($/ton)
No Fugitive Monitoring	57,914									
1a Annual	34,749	23,166		$1,473,180	$16,315,457	$704		$13,240,563	$572	
1b Semiannual	23,166	34,749	11,583	$1,473,180	$22,674,832	$653	$549	$18,062,492	$520	$416
1c Quarterly	11,583	46,332	11,583	$1,473,180	$35,359,207	$763	$1,095	$29,209,420	$630	$962

Table 2-35h. Summary of Cost of VOC Control for Compressor Stations, 2025

Option	VOC Emissions (tpy)	Cummulative Emission Reduction (tpy)	Incremental Emission Reduction (tpy)	Capital Cost ($)	Without Savings: Annualized Cost ($/yr)	Without Savings: Total Cost Effectiveness ($/ton)	Without Savings: Incremental Cost Effectiveness ($/ton)	With Savings: Annualized Cost ($/yr)	With Savings: Total Cost Effectiveness ($/ton)	With Savings: Incremental Cost Effectiveness ($/ton)
No Fugitive Monitoring	11,311									
1a Annual	6,787	4,524		$1,473,180	$16,315,457	$3,606		$13,240,563	$2,927	
1b Semiannual	4,524	6,787	2,262	$1,473,180	$22,674,832	$3,341	$2,811	$18,062,492	$2,662	$2,132
1c Quarterly	2,262	9,049	2,262	$1,473,180	$35,359,207	$3,908	$5,607	$29,209,420	$3,228	$4,928

3.0 ENGINEERING CERTIFICATIONS

Table 3-1 summarizes the number of the facilities in the years 2020 through 2025 that are affected by this final rule that require certification. Certifications would be allowed to be performed by either an in-house engineer or a professional engineer. In the 2018 NSPS Proposal TSD, the EPA estimated the costs of these certifications to be $358.09 for an in-house certification and $546.66 for certification by a professional engineer (2016$). Comments were received that indicated that these estimates significantly underestimated the cost for certifications. One commenter[78] indicated that EPA's estimate was almost five times lower than the best cost that they have been able to find ($2,500), while another commenter[79] cites costs ranging from $2,000 - $9,000 per certification, with the actual cost being dependent on the site complexity, thus the amount of engineering design time involved. Based on this information, a cost of $4,500 was used as the cost for professional engineering certification. This number was obtained by averaging $2,000, $9,000, and $2,500 (the estimates provided by commenters). This estimate represents a cost over eight times larger than the cost used for the analysis for the proposed rule. For the in-house certification, the ratio of the proposed cost ($358.09/$546.66 = 0.66) was applied to the $4,500 cost to obtain a cost of $2,950. More details on the nationwide impacts of engineering certifications are discussed in the RIA for this final rule.

Table 3-1. Estimated Number of Affected Facilities Requiring Certifications for Years 2020 through 2025

Type of Affected Facility	2020	2021	2022	2023	2024	2025
Pneumatic Pumps	497	497	497	497	497	497
Centrifugal Compressors	0	0	0	0	0	0
Reciprocating Compressors	10	10	10	10	10	10
Storage Vessels	1,026	1,074	1,127	1,162	1,182	1,194
Total	**1,533**	**1,581**	**1,634**	**1,669**	**1,689**	**1,701**

[78] Venditti, Charles E., Cuntrymark Energy Resources, LLC. Comments on Oil and Natural Gas Sector: Emission Standards for New and Modified Sources Proposed Rule OOOOa. Docket Item Number EPA-HQ-OAR-2017-0483-0757, p. 5.

[79] Todd, Matthew, American Petroleum Institute. Comments on Docket ID No. EPA-HQ-OAR-2017-0483; EPA's "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration; Proposed Rule"; 83 Fed. Reg. 52056 (October 15, 2018). December 17, 2018. Docket Item Number EPA-HQ-OAR-2017-0483-0801, p. 43.

Attachment 1

Memorandum. Summary of Data Received on the October 15, 2018 Proposed Amendments to 40 CFR Part 60, Subpart OOOOa Related to Model Plant Fugitive Emissions.

Attachment 2

Memorandum. Baseline Emissions for Compressor Stations Based on Subpart W Fugitive Emissions Data.

Attachment 3

Memorandum. Methodology for Conducting Fugitive Emissions Leak Survey Time and Leak Counts from NSPS OOOOa Compliance Reports.

MEMORANDUM

TO: EPA Docket No. EPA-HQ-OAR-2017-0483

DATE: February 10, 2020

SUBJECT: Summary of Data Received on the October 15, 2018 Proposed Amendments to 40 CFR Part 60, Subpart OOOOa Related to Model Plant Fugitive Emissions

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1.0 Purpose

The Environmental Protection Agency (EPA) proposed amendments to the new source performance standards (NSPS) at 40 Code of Federal Regulations (CFR) part 60, subpart OOOOa, for the Oil and Natural Gas Sector on October 15, 2018 (83 FR 52056). The purpose of this memorandum is to provide a high-level summary of information received in public comments on the proposed amendments to NSPS OOOOa related to fugitive emissions, particularly related to the EPA's model plant analysis. While the impact on all model plant sizes is discussed, there is specific emphasis on information and data relevant to low production well sites (i.e., where the total combined oil and natural gas production for the well site is less than 15 barrels of oil equivalent (boe) per day).

For the final rule, no changes were made to the 2018 model plants directly based on the information summarized in this memorandum. However, based on further evaluation of existing information and comments received on the proposed amendments, changes were made to the low production model plants for the final rule.[1]

[1] The updated model plant analyses are discussed in the final Technical Support Document (TSD) (Section 2) and in the preamble (Sections V.B and VI.B) for the final rule.

2.0 Introduction

The EPA's decisions on the October 15, 2018, proposed amendments related to the fugitive emission requirements in NSPS OOOOa were influenced by cost and emissions impacts analyses conducted using representative model plants. Several public comments were received on the model plants and the associated analyses, and some of these comments included data and analyses. A significant aspect of the proposed fugitive amendments was the subcategorization of well sites based on production levels with less frequent monitoring requirements proposed for low production well sites. Several public comments were received on the EPA's October 15, 2018, proposed amendments to the fugitive emission requirements contained in NSPS OOOOa, with many focused on the proposed subcategorization of well sites and the requirements for low production well sites. This memorandum summarizes information received on the model plants and analyses, with emphasis on comments related to low production well sites. The most substantive data was submitted by three commenters, the Environmental Defense Fund, et. al. (Environmental Commenters),[2] the Independent Petroleum Association of America, et. al. (IPAA),[3] and the American Petroleum Institute (API).[4] The data provided by these three commenters and their associated analyses and conclusions are discussed in Sections 3.0, 4.0, and 5.0, respectively. Other comments that were submitted without detailed supporting data are also briefly discussed in Section 6.0.

[2] Comments on Proposed Reconsideration from Environmental Defense Fund, et. al (Environmental Commenters). December 17, 2018. EPA-HQ-OAR-2017-0483-2041 and attachments.
[3] Comments on Proposed Reconsideration from Independent Petroleum Association of America, et. al. December 17, 2018. EPA-HQ-OAR-2017-0483-1006.
[4] Comments on Proposed Reconsideration from the American Petroleum Institute. December 17, 2018. EPA-HQ-OAR-2017-0483-0801.

3.0 Environmental Commenters

Section 3.1 provides an overview of the data submitted by the Environmental Commenters, as well as the analyses and conclusions provided. Section 3.2 presents an evaluation of this data and analyses, and Section 3.3 discusses additional considerations.

3.1 Overview of Data

In comments on the 2018 proposed reconsideration, Environmental Commenters stated that "EPA's CH_4 emission factors for both the low and non-low production sites, which are based in part on data collected in the mid-1990s, underestimate site-level fugitive CH_4 emissions, often by more than a factor of two."[5] The estimates of methane emission factors used by Environmental Commenters are based on site-level measurement data from more than 1,000 sites in eight basins.[6] Environmental Commenters indicated that the data was obtained from eight individual studies described in Omara et. al. (2018).[7] A short overview of the Omara 2018 study is provided in Appendix A.

Measurements included emissions from all sources (vented and fugitive) at the well sites. In order to obtain an estimate of the fugitive emissions, the total emissions were scaled by roughly 50% based on a fugitive fraction analysis conducted by EDF using 300 measured sites with fugitive emissions data in the City of Fort Worth (FW) Study.[8] In a meeting between EPA and EDF on April 23, 2019, EDF indicated that it had corroborated the 50% fugitive emissions

[5] EPA-HQ-OAR-2017-0483-2041, page 1.
[6] Appendix G of EPA-HQ-OAR-2017-0483-2041: A technical assessment of the forgone methane emissions reductions as a result of EPA's proposed reconsideration of the 2016 NSPS fugitive emissions requirements for oil and gas production sites. Mark Omara, PhD, Senior Research Analyst, Environmental Defense Fund, Austin, TX. December 2018.
[7] Omara et. al (2018) - Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate. Environ. Sci. Technol. 2018, 52, 12915−12925.
[8] City of Fort Worth. Natural Gas Air Quality Study Final Report. Prepared by Eastern Research Group and Sage Environmental Consulting for the City of Fort Worth. July 13, 2011.

portion estimated using data from the FW Study against the EPA's Greenhouse Gas Inventory (GHGI), which according to EDF indicates that fugitive emissions account for about 50% of production emissions.[9]

In the Environmental Commenters' analysis, the number of new oil and gas production sites subject to the proposed amendments was determined using DrillingInfo (DI) data. Geospatial analysis with ArcGIS was used to determine the total number of sites per year and data for wells with known location were aggregated into site-level information. Total well site oil and gas production amounts were calculated and classified as either low (<15 boe) or non-low (≥15 boe) consistent with EPA's proposed subcategorization, and further categorized into the EPA's current well site model plant categories of (a) gas well site, (b) oil well site with gas-to-oil ratio (GOR) <300, and (c) oil well site with GOR >300. Environmental Commenters concluded that the data show that well sites have higher fugitive emissions than estimated by the EPA at proposal and present the results of their analysis for each affected facility subcategory as shown in Table 1. Also presented in Table 1 are the EPA's 2020 final model plant values, reflecting adjustments made to the low production model plants between the proposed and final rule based on an additional evaluation of existing information and comments received on the proposed amendments, as further described in the Technical Support Document (TSD) for this final rule.

[9] Page 13 of Comments on EPA's Proposed Reconsideration of the Oil & Gas New Source Standards David Lyon, Hillary Hull, Peter Zalzal and Rosalie Winn, EDF. Presented to EPA on April 23, 2019.

Table 1. Comparison of EDF vs. EPA Methane Emissions for Affected Sources[10]

Affected Facility	Fugitive Emissions (tpy CH_4)		
	EDF Studies Facilities	EPA 2018 Proposed Model Plants	EPA 2020 Final Model Plants[a]
Non-Low Production: Gas	15.5	5.9	5.9
Non-Low Production: Oil >300 GOR	11.8	3.0	3.0
Non-Low Production: Oil <300 GOR	10.4	2.1	2.1
Low Production: Gas	6.1	4.8	3.5
Low Production: Oil >300 GOR	4.7	2.6	1.5
Low Production: Oil <300 GOR	1.8[b]	1.8	2.0

[a]The EPA's 2020 final model plant analyses are discussed in the final Technical Support Document (TSD) (Section 2) and in the preamble (Sections V.B and VI.B) for the final rule.
[b]Based on the EPA's 2018 proposed model plants due to lack of measurement data.

3.2 Evaluation of Data

Site-level natural gas production and methane emissions from the 1,009 sites that were analyzed were provided in Appendix A of Appendix G of Environmental Commenters.[11] Appendix A of the comments did not distinguish sites by site sub-type (i.e., gas, oil >300 GOR, or oil <300 GOR). A brief overall summary of fugitive methane emissions data provided in this appendix by non-low production sites and low production sites is presented in Table 2a.

[10] Comparison of EDF and EPA methane emissions obtained from Table 1 of Appendix G of EPA-HQ-OAR-2017-0483-2041.
[11] Appendix A of Appendix G of EPA-HQ-OAR-2017-0483-2041: A technical assessment of the forgone methane emissions reductions as a result of EPA's proposed reconsideration of the 2016 NSPS fugitive emissions requirements for oil and gas production sites. Mark Omara, PhD, Senior Research Analyst, Environmental Defense Fund, Austin, TX. December 2018.

Table 2a. Evaluation of EDF Provided Fugitive Methane Emissions[a, b]

Study (Number of Well Sites)	Min	Max	Average	Median
All Studies (1,009)				
Site-Level NG Production (MCF)	0.4	78,024	1,423	390
Fugitive Methane Emissions (tpy)	0.0	1,257	19	4
Non-Low Production (771)				
Site-Level NG Production (MCF)	91	78,024	1,849	668
Fugitive Methane Emissions (tpy)	0.1	1,257	23	5
Low Production (238)				
Site-Level NG Production (MCF)	0.4	89	40	38
Fugitive Methane Emissions (tpy)	0.0	115	7	2

[a]Non-low production >90 thousand cubic feet (MCF); low production <90 MCF.
[b]A 50% scaling factor was applied to the reported site-level methane emissions information in Appendix A Table of Appendix G to generate the minimum, maximum, average, and median fugitive methane emissions.

As shown in Table 2a, the median values for each of the three data sets are considerably lower than the averages (means). This indicates that the emission values are distributed more at the lower end of the methane emission range and that the average does not represent a typical value for this data set. For example, 82% of all the well sites had fugitive emissions less than the average value of 19 tpy and only 18% had emissions greater than the average. Similarly, 82% of the non-low production well sites and 74% of the low production well sites had emissions less than the average. It is worth noting that the median values in Table 2a are similar to the EPA's 2018 proposed low production model plant emissions of 4.8 tpy and EPA's 2020 final low production model plant emissions of 3.5 tpy. Figure 1 illustrates the full range of methane emissions from non-low production sites based on the information provided by Environmental Commenters. Figure 2 illustrates the full range of methane emissions from low production sites based on the information provided by Environmental Commenters.

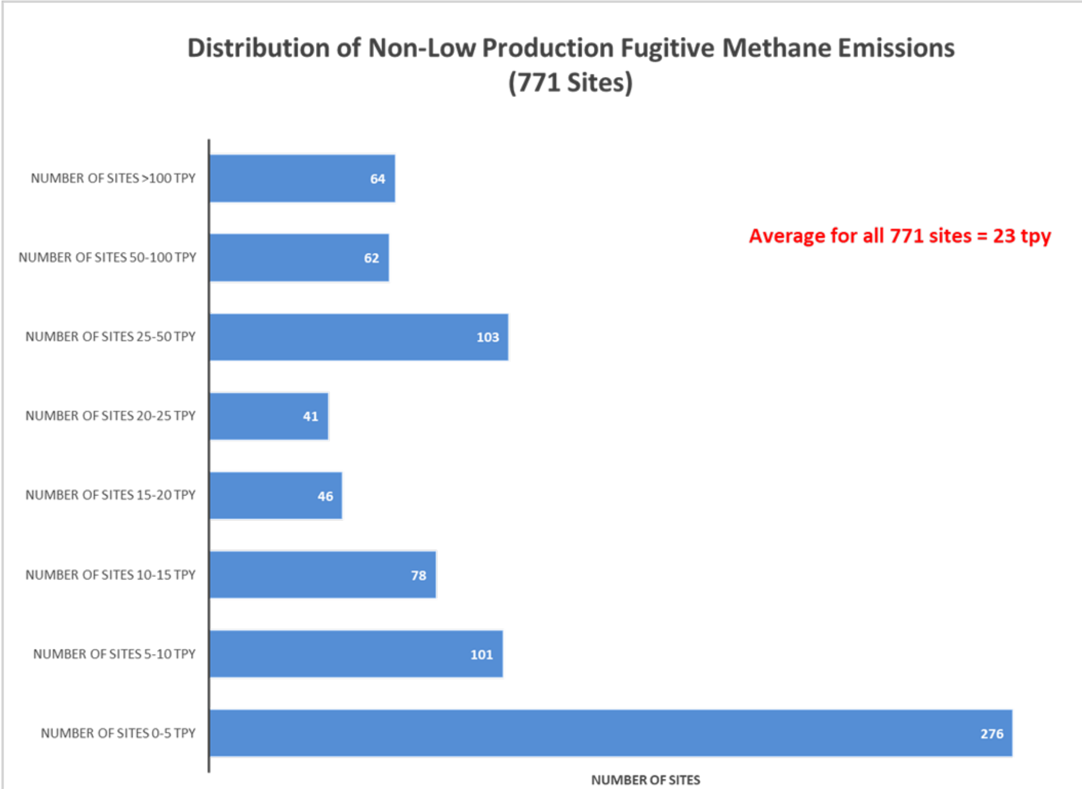

Figure 1. Distribution of Non-Low Production Fugitive Methane Emissions[12]

[12] Note that Figure 1 includes all emissions provided for non-low production (>90 MCF) and include those emissions reported as 0 in Appendix A of Appendix G to Environmental Commenters submittal.

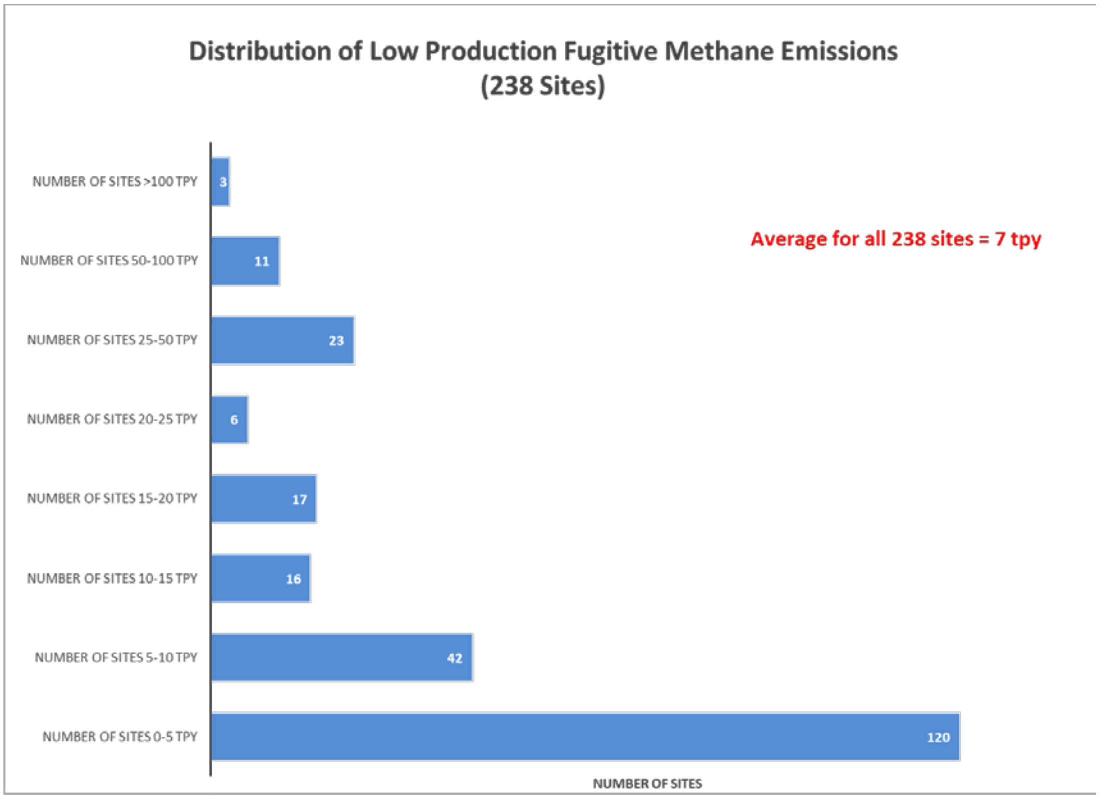

Figure 2. Distribution of Low Production Fugitive Methane Emissions[13]

Further details on the site-level methane emissions from the 1,009 studies were provided separately at a later date to the EPA that classified emissions based on the EPA's current well site model plant categories distinguishing sites by gas, oil >300 GOR, or oil <300 GOR.[14] An analysis of fugitive methane emissions data provided in Appendix A of Appendix G to Environmental Commenters in combination with additional information received with the production breakdown is presented in Table 2b. As Table 2b shows, the median methane emissions from low production gas sites based on the fugitive emissions data provided by Environmental Commenters are similar to the EPA's 2018 model plant estimate at proposal of 4.8 tpy and 2020 final model plant estimate of 3.5 tpy.

[13] Note that Figure 2 includes all emissions provided for low production (<90 MCF) and include those emissions reported as 0 in Appendix A of Appendix G to Environmental Commenters submittal.
[14] Attachment to Email from Rosalie Winn, EDF to David Cozzie, et.al., EPA. May 22, 2019. Appendix G productionBins_and_available_site_level_data_.xlsx.

Table 2b. Analysis of EDF Provided Fugitive Methane Emissions[a, b, c]

Study (Number of Well Sites)	Fugitive Emissions (tpy CH_4)			
	Min	**Max**	**Average**	**Median**
All Studies (497)				
Gas (325)	0.0	407	17	7
Oil >300 GOR (170)	0.09	618	19	5
Oil <300 GOR (2)	5	9	7	7
Non-Low Production (348)				
Gas (258)	0	407	20	9
Non-low production: Oil >300 GOR (88)	0.2	618	31	8
Non-low production: Oil <300 GOR (2)	5	9	7	7
Low Production (149)				
Low production: Gas (67)	0	39	6	4
Low production: Oil >300 GOR (82)	0.09	33	6	3
Low production: Oil <300 GOR	No data			

[a]Non-low production >90 MCF; low production <90 MCF.
[b]A 50% scaling factor was applied to the reported site-level methane emissions information in Appendix A Table of Appendix G to generate the minimum, maximum, average, and median fugitive methane emissions.
[c]Analysis reflects information provided by EDF where the site's reported oil and gas production was provided.

3.3 Additional Considerations

The estimate of 50% of total emissions being fugitive emissions is a major assumption that impacts the overall fugitive analysis conducted by Environmental Commenters and substantially influences the magnitude of fugitive methane emissions presented in comments. As discussed below, available information indicates a wide range of the ratio of fugitive emissions to total site emissions which provide a band of uncertainty with regard to the conclusions that may be drawn from the Environmental Commenters analysis and conclusions.

After the close of the comment period, additional detail on the approach to calculating the 50% fugitive emissions portion was provided to the EPA by EDF.[15] According to EDF, an analysis of the measurement data from the FW study indicates that "The % of total emissions attributable to fugitive sources varies from ~0% to 100% for the 300 sites with emissions data (number of low-production sites =19, non-low production sites = 222, sites with no reported production = 59)."[16] Further, EDF stated that "The mean values were statistically similar for low-production, non-low production, and sites with no reported production, and was ~54%, with a spread of ~48% to 60%."[17] EDF believes the estimate of the fugitive emissions fraction is corroborated by GHGI and provided details on how in their estimation, analyzing GHGI methane emissions for natural gas systems in the production segment validates the magnitude of the ~50% fugitive fraction of total emissions, where EDF presented a fugitive fraction range based on 2014-2017 GHGI fugitive emissions between 55 and 57%.

API submitted supplemental comments that provided specific remarks on EDF's assessment.[18] In these comments, API indicated that the approach EDF used to estimate that 50% of total emissions are attributable to fugitive emissions is flawed. API noted several concerns regarding how EDF estimated the fraction of methane emissions from well sites that are attributable to fugitive emission components noting, in addition, that it could not reach the same conclusion regarding the specific fraction attributable to fugitive emissions. In brief, API noted the following four main concerns regarding EDF's assessment:

[15] Attachment to Email from Rosalie Winn, EDF to David Cozzie, et.al., EPA. May 22, 2019. Estimating the fraction of site-level total emissions attributable to fugitive sources in Appendix G.
[16] Id. Page 1.
[17] Id. Page 1.
[18] Letter from Matthew Todd, American Petroleum Institute to Peter Tsirigotis, EPA. May 24, 2019.

1. The FW Study only quantifies methane emissions from fugitive components and tanks in the total site-wide emissions value.
2. Application of percentage (given the data that is used to derive it), is misleading as it would not accurately portray the average percentage of emissions that should be assigned to fugitives.
3. The FW Study was completed in 2011 prior to the NSPS OOOO, which established requirements that would reduce tank emissions and emissions from other sources at the site. For that reason, the benefits associated with the controls required would not be reflected in the overall site emissions determined in the study. This could impact the results of the FW Study.
4. The FW Study cited does not appear to identify any episodic or unusual emission events.

Under concern 2, API added that: "In more recent work funded by eNGOs in 2016 and published by Zavala-Araiza, et al.13[19], it was found that 13% of site-wide emissions were attributable to fugitive emissions. Additionally, another document on methane emissions from the oil and gas sector for sites in New Mexico found 15% of emissions were attributable to fugitive emissions.[20] The reasoning for selecting the outdated City of Fort Worth was not addressed by the eNGOs."[21]

In order to compare to the information presented by API, the EPA examined information from the 2017 Greenhouse Gas (GHG) Reporting program for onshore production. The total reported methane emissions for all onshore production emissions sources were 44 million metric tons (MMT) of carbon dioxide equivalent (CO_2e). Of this total, 7.8 MMT CO_2e, or 18%, were

[19] Zavala-Araiza, D. et al. Super-emitters in natural gas infrastructure are caused by abnormal process conditions. Nat. Commun. 8, 14012 doi: 10.1038/ncomms14012 (2017).
[20] https://www.edf.org/sites/default/files/new-mexico-methane-analysis.pdf.
[21] Letter from Matthew Todd, American Petroleum Institute to Peter Tsirigotis, EPA. May 24, 2019. Page 9.

reported for equipment leaks. According to the 2017 GHG, pneumatic devices accounted for 25.5 MMT CO_2e (51%) and storage tanks represented methane emissions of another 2 MMT CO_2e (5%).[22]

4.0 IPAA

Section 4.1 provides an overview of the data submitted by the IPAA, as well as the analyses and conclusions provided. Section 4.2 presents an evaluation of this data and analyses.

4.1 Overview of Data

In comments on EPA's proposed reconsideration, IPAA indicated that it solicited component counts from low production wells from members in 13 states (Arkansas, Colorado, Indiana, Kansas, Kentucky, Michigan, Montana, Nebraska, Ohio, Oklahoma, Pennsylvania, Texas, and Virginia). Comments submitted by IPAA presented low production component counts for natural gas operations in eight states that reported information. In their comments, IPAA observed that EPA's model plant is dominated by emissions from valves and storage vessels. For all three low production model plants, IPAA stated that "In each of these cases, the primary factors in the emissions profile are valves and thief hatches on storage vessels."[23] A summary of the assembled component count information provided by IPAA is shown in Table 3.

[22] 2011–2017 Greenhouse Gas Reporting Program Industrial Profile: Petroleum and Natural Gas Systems. October 2018.
[23] Comments on Proposed Reconsideration from Independent Petroleum Association of America, et. al. December 17, 2018. EPA-HQ-OAR-2017-0483-1006. Page 30.

Table 3. Low Production Component Count Information Provided by IPAA

State	Type of Wells	Number of Natural Gas Well Sites	Average Number of Storage Vessels Per Wellsite	Average Number of Wellheads Per Wellsite	Average Number of Valves Per Wellsite
PA	Gas	1,631	1	1	23
OK	Gas	27	2	1	38
OH	Gas	10	10	10	22
TX	Gas	10	2	1	25
KS	Gas	6	1	1	11
MI	Gas	4	3	2	53
KY	Gas	2	1	1	14
VA	Gas	1	1	1	12

On page 38 of IPAA's comment letter, it notes that (in reference to the component counts collected): "These results are not intended to be presented as statistically accurate or fully representative of the population of low production wells. However, they are illustrative of the challenge of defining a Model Low Production Well plant." In supplemental comments submitted by Environmental Commenters[24] in response to IPAA's comments, Environmental Commenters made the following statement:

"These data are nontransparent and lack key contextual information necessary for meaningful analysis. For example, there is no information provided on a site-level basis that would indicate whether these data are representative of new or modified low-production well sites under a standard definition. For instance, there is no oil/gas production information that would indicate whether these are low-production sites, no information on the age of such sites, etc. IPAA itself admits this data is "not intended to be presented as statistically accurate or fully

[24] Supplemental Comments on Proposed Rule: Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration submitted by Environmental Commenters. February 21, 2019. EPA-HQ-OAR-2017-0483-2194.

representative of the population of low production wells." (IPAA Comments at 31.) It would be arbitrary for EPA to rely on such nontransparent data in a final rule."

4.2 Evaluation of IPAA Data

The average and weighted average number (based on the number of wells per state) of storage vessels, wellheads, and valves were calculated from the information provided in Table 3. The results are provided in Table 4.

Table 4. Summary of Average and Weighted Average Counts of IPAA Data

	Equipment Per Low Production Gas Well Site		
	Storage Vessels	**Wellheads**	**Valves**
Average	2.6	2.3	24.8
Weighted Average	1.1	1.1	23.3

Note that no data was provided by IPAA for oil well sites or oil well sites with associated gas. Since the component count information provided by IPAA was limited to low production gas wells only, a comparison could not be made to all three of the EPA's existing low production model plant categories. The EPA substituted the weighted average storage vessels, wellheads and valve counts shown in Table 4 for those in the EPA model plant and compared the resulting total fugitive emissions. This comparison is presented in Table 5.

Table 5. Comparison of Low Production Model Plant Methane Emissions

Description	Number of Wellheads	Number of Tanks	Number of Valves	Methane Emissions (tpy)
EPA 2018 Proposed Low Production Gas Well Model Plant	2	1	100	4.8
EPA 2020 Final Low Production Gas Well Model Plant[a]	2	1	65	3.5
Gas Well Model Plant Using Weighted Average IPAA Data	1	1	23	2.5

[a]The EPA's 2020 final model plant analyses are discussed in the final Technical Support Document (TSD) (Section 2) and in the preamble (Sections V.B and VI.B) for the final rule.

5.0 API

Section 5.1 provides an overview of the data submitted by API, as well as the analyses and conclusions provided. Section 5.2 presents an evaluation of this data and analyses.

5.1 Overview of Data

On February 22, 2018, API submitted leak monitoring data to EPA.[25] Subsequently API referred to and supplemented that analysis with information provided on December 17, 2018, in comments on the proposed reconsideration.[26] Based on API's data collection effort and analysis, API indicated that it found that the percentage of leaking components found prior to the implementation of any leak monitoring program was less than the number incorporated in the emission factors used by EPA for the baseline fugitive emission estimates. API indicated that the result was that the baseline emissions, and the emission reductions estimated to be achieved by the fugitive program, had therefore been overestimated by the EPA.

[25] Letter from Matthew Todd, API to Peter Tsirigotis, EPA. Re: Leak Monitoring Data Analysis in Support of EPA's Reconsideration of the "Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources; Final Rule." February 22, 2018. EPA-HQ-OAR-2017-0483-0015.
[26]EPA-HQ-OAR-2017-0483-0801.

In response to API's leak monitoring data, the EPA conducted an analysis of the well site fugitive emissions data provided prior to the 2018 proposal.[27] Overall, after reviewing the data provided by API, the EPA found areas of uncertainty that could affect how the data are interpreted and determined at that time that it was appropriate to retain the emission factors used for the 2016 NSPS OOOOa. In API's comments on the 2018 proposed reconsideration, API provided a response to EPA's analysis of the well site fugitive emissions monitoring data where API disagrees with EPA's interpretation and the conclusion that the LDAR data submitted by API could not be relied upon.[28]

In addition, API also provided summary data and analysis of subpart OOOOa data collected from member companies over a period of two years.[29] A summary of the number of sites and leaks based on the API collected semiannual survey data is provided in Table 6.

Table 6. API Subpart OOOOa Fugitive Emissions Monitoring Data

Survey Number	Total Number of Leak Surveys	Total Number of Leaks	Leaks per Survey
1	3,367	4,779	1.42
2	1,776	2,290	1.29
3	721	752	1.04
4	119	107	0.90

In their comment letter, API states that: "The Subpart OOOOa data confirm that semi-annual leak monitoring provide limited incremental environmental benefit and support EPA's proposed annual survey frequency." The survey monitoring data provided by API represent measurements from over 4,000 sites and indicate a lower number of leaks compared to what the EPA estimated in the proposed rule. The semiannual LDAR surveys conducted in compliance

[27] Memorandum to EPA Docket No. EPA-HQ-OAR-2017-0483. EPA Analysis of Well Site Fugitive Emissions Monitoring Data Provided by API. April 17, 2018. EPA-HQ-OAR-2017-0483-0036.
[28] See Attachment A to EPA-HQ-OAR-2017-0483-0801.
[29] See Attachment A to EPA-HQ-OAR-2017-0483-0801, Attachment B.

with Subpart OOOOa show that the EPA has overestimated the emissions reductions associated with the LDAR program (by overestimating the number of leaking components for the model plant) and support an annual monitoring frequency, in API's opinion. According to API: "The Subpart OOOOa data confirm that semi-annual leak monitoring provide limited incremental environmental benefit and support EPA's proposed annual survey frequency. While the dataset were not produced from a controlled experiment with a collection of well sites undergoing semi-annual monitoring and another set undergoing annual monitoring, the data clearly indicate that moving to an annual frequency will not result in an appreciable increase in emissions."

5.2 Evaluation of API Information and Analyses

The uncontrolled emission factors for non-thief hatch fugitive emission components EPA used to estimate model plant emissions for the 2018 reconsideration proposal are based on Table 2-4 of the Protocol for Equipment Leak Emission Estimates ("1995 Protocol") and shown in Table 6 below. The emissions factor used for thief hatches on controlled storage vessels that EPA used for the 2018 proposal is 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.

The leak monitoring data API submitted indicated an overall leak fraction of 0.004 leaking components detected using OGI per the total number of components surveyed compared to 0.02 (at 500 parts per million (ppm)) and 0.0165 (at 10,000 ppm) from the EPA Protocol Document. Note that these leak fractions are not specifically stated in the Protocol Document, but API performed a back-calculation of the fraction of leaking components using Table 5-7 of the Protocol document and the weighted leak fraction for all components using the number of each component per model plant.[30]

In API's analysis, API scaled EPA's original component emission factors (except thief hatches) by 0.4%/2.5% and 0.4%/1.65% to estimate revised and lower component leak rates in kg/hr. Using the newly estimated leak rate, API back-calculated revised mass-based leak rates for all components using Table 2-4 of the Protocol document and provided revised methane component emission factors as shown in Table 7.

Table 7. Methane Emission Factors (kg/hr/component)

Component	EPA 2018 Emission Factor (kg/hr/component)	Emission Factor (kg/hr/component) @500 ppm (w/API 0.4% Leak Rate)	Emission Factor (kg/hr/component) @10,000 ppm (w/API 0.4% Leak Rate)
Valves	0.0045	0.00072	0.00109
Flanges	0.00039	0.000062	0.000094
Connectors	0.0002	0.000032	0.000048
OEL	0.002	0.00032	0.00048
PRV	0.0088	0.0014	0.0021
Thief Hatches[a]	0.1296	N/A	N/A

[a]Updated emission factor for thief hatches was not included in API's analysis. (EPA's 2018 emission factor for thief hatches retained in analysis.)

The revised component emission factors based on API's analysis at the 10,000 ppm leak definition level as shown in Table 7 were applied to EPA's 2018 proposed existing model plant. Using API's 0.4% leak rate at 10,000 ppm and recalculated component emission factors for each non-low and low production model plant categories results in the total model plant methane emissions presented in Table 8.

[30] See letter from Matthew Todd, American Petroleum Institute to Peter Tsirigotis, EPA. February 22, 2018, Attachment "API Updated Analysis.xls" EPA-HQ-OAR-2017-0483-0015.

Table 8. Comparison of API vs. EPA Methane Emissions for Model Plants using API's Revised Leak Rate and Component Emission Factors

Affected Facility	Model Plant Fugitive Methane Emissions (tpy)		
	API[a]	EPA 2018 Proposed Model Plants	EPA 2020 Final Model Plants[b]
Non-Low Production: Gas	2.1	5.9	5.9
Non-Low Production: Oil >300 GOR	1.4	3.0	3.0
Non-Low Production: Oil <300 GOR	1.2	2.1	2.1
Low Production: Gas	1.8	4.8	3.5
Low Production: Oil >300 GOR	1.3	2.6	1.5
Low Production: Oil <300 GOR	1.1	1.8	2.0

[a]Calculated using the emission factors at 10,000 ppm shown in Table 6.
[b]The EPA's 2020 final model plant analyses are discussed in the final Technical Support Document (TSD) (Section 2) and in the preamble (Sections V.B and VI.B) for the final rule.

6.0 Other Commenters

Three other commenters submitted information related to the fugitive model plants and emissions. Section 6.1 discusses the comments submitted by the Ohio EPA, Section 6.2 discusses the comments submitted by Chevron, and Section 6.3 discusses the comments submitted by the Texas Independent Producers & Royalty Owners Association (TIPRO).

6.1 Ohio EPA

In comments on the proposed reconsideration, Ohio EPA provided information on average component counts used to develop a model plant representing Ohio facilities.[31] Comments from Ohio EPA indicate that information presented is based on data from the Ohio Department of Natural Resources, Ohio EPA's own information, and subpart W default component counts. Limited information was presented in Ohio EPA's comments and it is unclear if Ohio EPA's model plant is for all production (low and non-low) and whether the component counts are for gas only, oil well sites or oil wells with associated gas. Model plant component

[31] Comments on Proposed Reconsideration from Ohio EPA. December 17, 2018. EPA-HQ-OAR-2017-0483-1741

count information provided in comments by Ohio EPA is in Tables 9a and 9b, per unit of production and per model plant, respectively.

Table 9a. Ohio EPA Model Plant Component Count Information provided in Comments - Per Unit of Production[32]

Production Equipment	Model Plant[a] Production Equipment Counts	Average Component Count per Unit of Production				
		Valves	Flanges	Connectors	OELs	PRVs
Well Heads	3.6	5	10	4	0	1
Separators	3.6	6	12	10	0	0
Headers	3.6	5	10	4	0	0
Heater/Treater	3.6	8	12	20	0	0
In-Line Heater	3.6	14	0	65	2	1
Meters/Piping	3.6	12	0	45	0	0

[a]It is unclear if Ohio EPA's model plant is for all production (low and non-low) and whether the component counts are for gas only, oil well sites or oil wells with associated gas.

Table 9b. Ohio EPA Model Plant Component Count Information provided in Comments - Per Model Plant[33]

Production Equipment	Average Component Count per Model Plant[a]				
	Valves	Flanges	Connectors	OELs	PRVs
Well Heads	18	36	14	0	4
Separators	22	43	36	0	0
Headers	18	36	14	0	0
Heater/Treater	29	43	72	0	0
In-Line Heater	50	0	235	7	4
Meters/Piping	43	0	162	0	0
	180	**158**	**533**	**7**	**8**

[a]It is unclear if Ohio EPA's model plant is for all production (low and non-low) and whether the component counts are for gas only, oil well sites or oil well with associated gas.

[32] Id. Page 3.
[33] Id. Page 3.

6.2 Chevron

In response to EPA's request for information collected from implementing fugitive monitoring programs, Chevron provided information on recent Method 21 OOOOa surveys.[34] In general Chevron uses OGI for compliance, but at their San Joaquin Valley Business Unit, in California Method 21 is used to comply with NSPS OOOOa fugitive monitoring requirements. The complete data set from Chevron's Method 21 monitoring program was provided in an attachment to their comments on the proposed reconsideration.[35] Chevron presented a leak occurrence rate of 0.04%, which is substantially lower than EPA has estimated according to Chevron, adding that the data support requiring no more than annual monitoring for leak detection surveys. This leak rate is also an order of magnitude lower than the leak rate provided by API (0.4%) in their comments. A brief summary of the data provided by Chevron is provided in Table 10. Note that Chevron did not indicate in their comment letter how long fugitive monitoring had been performed nor did the information specify the type of sites that were part of the monitoring program.

Table 10. Summary of Chevron Method 21 Leak Survey Data

Survey Time Period	Count of Components Surveyed	Number of Leaks	Components Leaking from Field Surveys
2017 1H	51,834	30	0.06%
2017 2H	50,264	9	0.02%
2018 1H	54,345	20	0.04%
2018 2H	38,756	16	0.04%

[34] Comments on Proposed Reconsideration from Chevron. December 14, 2018. EPA-HQ-OAR-2017-0483-0754.
[35] Id. Attachment A - APPENDIX A: Leak Occurrence and Concentration Data from Chevrons Method 21 OOOOa Program, Per Inspection and Component Type.

6.3 TIPRO

In their comments on the proposed reconsideration, TIPRO indicated that it solicited information on component counts for low production wells in Texas. According to TIPRO, based on the limited industry information it was able to collect, a trend could not be determined, however, TIPRO argued that the data was not consistent with the FW data and that more information and data on low production wells are needed.

7.0 Summary

The purpose of this memorandum is to provide a high-level summary and brief evaluation of information received in comments on the proposal, with a specific emphasis on information and data relevant to low production well sites.

Information from three commenters – EDF et. al. (Environmental Commenters), IPAA, and API – was reviewed in detail and analyzed and is discussed above. In addition, relevant comments received from three other commenters – Ohio EPA, Chevron, and TIPRO – are discussed above. However, these commenters did not provide enough detail to warrant detailed evaluation. (Note: Although the EPA's final 2020 model plant was not specifically changed as a result of the information provided by the Ohio EPA, it did confirm that the EPA well site model plant - at proposal and at the final rule - was reasonably representative of the information compiled for Ohio.)

The basic assertion of all the commenters was that the baseline fugitive emissions from well sites, as reflected in EPA model plants, were incorrect which biased the resulting cost effectiveness values and EPA decisions. The Environmental Commenters stated that the EPA model plant emission estimates were underestimated and IPAA and API stated that these emissions were overestimated. Table 11 summarizes the main emission estimates evaluated in this memorandum.

Table 11. Summary of Adjusted Model Plant Emissions

Model Plant and Description	Fugitive Methane Emissions (tpy)
Non-Low Production: Gas	
EPA Model Plant[a]	5.9
Environmental Commenters	15.5
IPAA	N/A
API	2.1
Non-Low Production: Oil >300 GOR	
EPA Model Plant[a]	3.0
Environmental Commenters	11.8
IPAA	N/A
API	1.4
Non-Low Production: Oil <300 GOR	
EPA Model Plant[a]	2.1
Environmental Commenters	10.4
IPAA	N/A
API	1.2
Low Production: Gas	
EPA 2018 Proposed Model Plant	4.8
EPA 2020 Final Model Plant[b]	3.5
Environmental Commenters	6.1
IPAA	2.5
API	1.8
Low Production: Oil >300 GOR	
EPA 2018 Proposed Model Plant	2.6
EPA 2020 Final Model Plant[b]	1.5
Environmental Commenters	4.7
IPAA	N/A
API	1.3
Low Production: Oil <300 GOR	
EPA 2018 Proposed Model Plant	1.8
EPA 2020 Final Model Plant[b]	2.0
Environmental Commenters	N/A
IPAA	N/A
API	1.1

[a]No changes made between the proposed and final rule to the non-low production model plants.
[b]The EPA's 2020 final model plant analyses are discussed in the final Technical Support Document (TSD) (Section 2) and in the preamble (Sections V.B and VI.B) for the final rule.

Figure 3 illustrates the different level of emission estimates for low production gas well sites model plants.

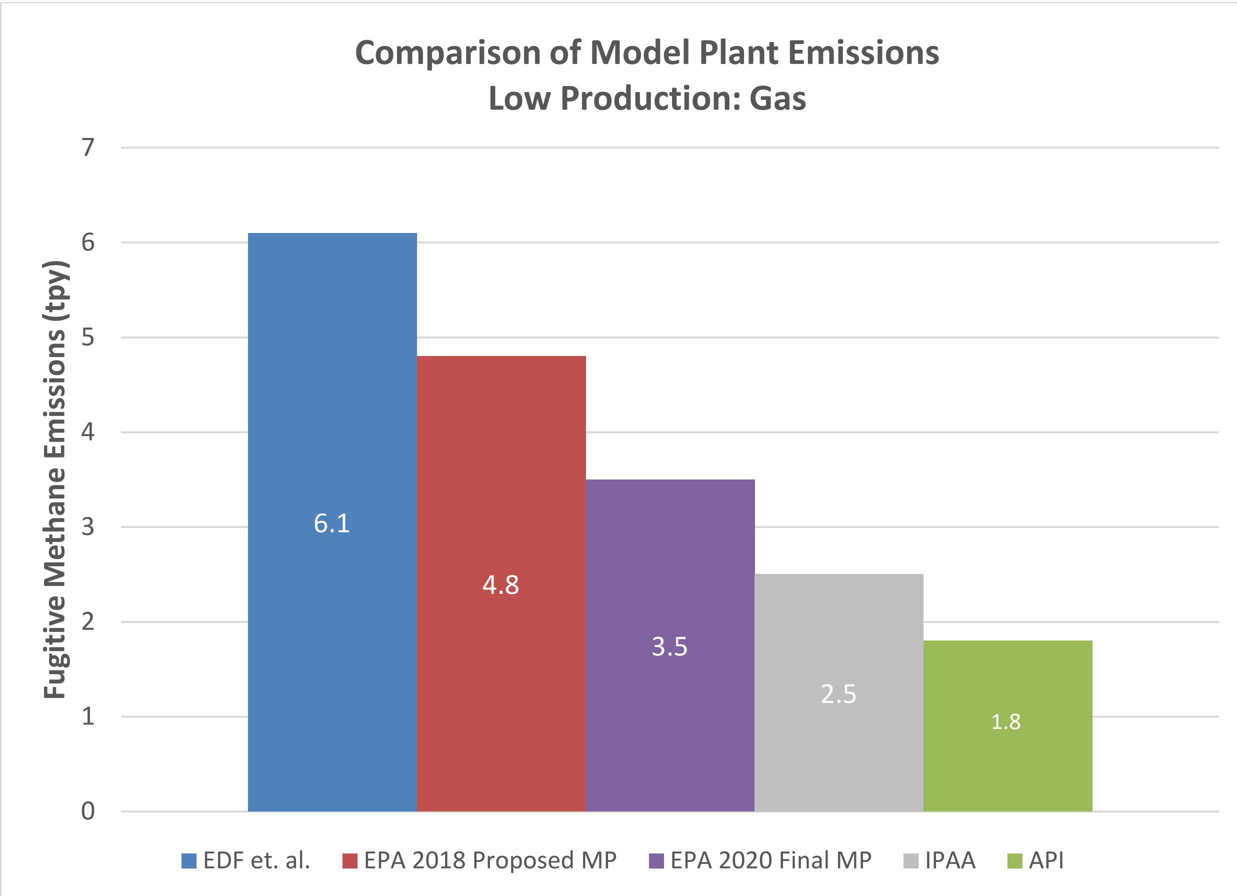

Figure 3. Methane Emissions for Gas Well Site Model Plants

As shown in Table 11 and Figure 3, the range of methane emissions varies considerably. A key metric considered by the EPA is the cost per unit of emission reduction (i.e., the "cost effectiveness"). Assuming the cost of a fugitive emission program and percentage of emission reduction are constants, this variability in the baseline emissions could result in a range of cost effectiveness values proportional to the range of emissions shown in Figure 3.

One key consideration in comparing these estimates is the universe of potential fugitive sources that are considered. The EPA model plants include valves, flanges, connectors, open-ended lines, pressure relief valves, and storage vessel thief hatches. Similarly, the adjustments to the model plant emissions based on the IPAA and API information only include emissions from these components. However, the definition of "fugitive emissions component" in §60.5430a of subpart OOOOa includes other potential sources of fugitive emissions. Therefore, the model plants likely underestimate fugitive emissions from this perspective. Similarly, the adjusted model plant emissions based on the IPAA and API information would include this same bias. The studies referenced and summarized by the Environmental Commenters are based on measurements that included all emissions from a well site. These studies would have included all the fugitive sources included in the "fugitive emissions component" definition. However, as discussed in Section 3.3, there is considerable uncertainty related to the broad assumption that around 50% of these total emissions are fugitive emissions.

In conclusion, given the significant variability in the equipment and configurations at oil and natural gas well sites, the creation of model plants to estimate fugitive emissions is especially challenging. The IPAA is correct in noting these challenges. None of the information submitted with the comments discussed in this memorandum is sufficient to perform a major overhaul of the model plant analysis, or to create a new methodology to estimate fugitive emissions. However, the analysis of the information reveals that the EPA model plant fugitive emission estimates fall within the ranges of well site fugitive emissions created by the Environmental Commenters on the upper end and the industry representatives at the lower end. The EPA acknowledges the data and information submitted by these commenters as summarized in this memorandum. While some of the information indicates that the EPA model plant analysis might underestimate fugitive emissions, there are several uncertainties and questions related to the provided information. In addition, and as presented in this memorandum, other commenters provided information that suggest that the EPA model plant analysis significantly overestimates fugitive emissions from well sites. After reviewing and considering all the information provided by commenters, the EPA concluded that the existing model plant analysis for (non-low production) well sites reasonably represents fugitive emissions from these sites, and the model plant for low production well sites was modified after re-evaluation of existing information and comments received on the proposed amendments, but not directly as a result of the information summarized in this memorandum. For a full discussion of EPA's 2020 final model plant analysis for all well sites, see Section 2 of the TSD for this final rule, available from the docket under Docket ID No. EPA-HQ-OAR-2017-0483.

Appendix A

<u>Omara et. al (2018) - Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate</u>[36]

The eight-independent site-level CH_4 emissions measurement studies EDF used to develop the above table are from the following eight basins and described in Omara et. al (2018):

1. ***Marcellus***
   - Goetz et. al (2015) - Atmospheric emission characterization of Marcellus Shale natural gas development sites **METHOD**: Downwind tracer flux (TF) measurements of downwind plumes of CH_4 and intentionally released tracers)
   - Omara (2016) - Methane emissions from conventional and unconventional natural gas production sites in the Marcellus Shale region. **METHOD**: Downwind tracer flux (TF) measurements of downwind plumes of CH_4 and intentionally released tracers)
2. ***Eagle Ford*** (Brantley (2014) - Assessment of methane emissions from oil and gas production pads using mobile measurements. **METHOD**: Downwind ground based stationary measurements using EPA OTM-33A.
3. ***Pinedale*** (Brantley (2014) - Assessment of methane emissions from oil and gas production pads using mobile measurements. **METHOD**: Downwind ground based stationary measurements using EPA OTM-33A.
4. ***Uinta*** (Robertson (2017) - Variation in methane emission rates from well pads in four oil and gas basins with contrasting production volumes and composition. **METHOD**: Downwind ground based stationary measurements using EPA OTM-33A.
5. ***Upper Green River (UGR)*** (Robertson (2017) - Variation in methane emission rates from well pads in four oil and gas basins with contrasting production volumes and composition. **METHOD**: Downwind ground based stationary measurements using EPA OTM-33A.
6. ***Barnett***
   - Brantley (2014). **METHOD**: Downwind ground based stationary measurements using EPA OTM-33A
   - ERG/FW Study (2011) - City of Fort Worth. Natural Gas Air Quality Study Final Report. **METHOD**: Direct onsite measurement with OGI.
   - Lan (2014) - Characterizing fugitive methane emissions in the Barnett Shale area using a mobile laboratory. **METHOD**: Downwind mobile measurements using Gaussian modeling.
   - Yacovitch (2015) - Mobile laboratory observations of methane emissions in the Barnett Shale region and **METHOD**: Downwind mobile measurements using Gaussian modeling.

[36] Omara et. al (2018) - Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate. Environ. Sci. Technol. 2018, 52, 12915−12925.

- Rella (2015) - Measuring emissions from oil and natural gas well pads using the mobile flux plane technique. **METHOD**: Downwind mobile measurements using Gaussian modeling.

7. ***Denver-Julesberg (DJB)***
   - Brantley (2014). **METHOD**: Downwind ground based stationary measurements using EPA OTM-33A
   - Robertson (2017). **METHOD**: Downwind ground based stationary measurements using EPA OTM-33A.
8. ***Fayetteville*** - (Robertson (2017) - Variation in methane emission rates from well pads in four oil and gas basins with contrasting production volumes and composition. **METHOD**: Downwind ground based stationary measurements using EPA OTM-33A.

The Omara study indicated that "We estimate that NG production sites emit total CH_4 emissions of 830 Mg/h, 63% of which come from the sites producing <100 Mcfd that account for only 10% of total NG production. Our total CH_4 emissions estimate is 2.3 times higher than the U.S. Environmental Protection Agency's estimate and likely attributable to the disproportionate influence of high emitting sites.[37]"

The Omara article additional concluded that: "Finally, our national estimate for total CH_4 emissions from NG production sites (830 Mg/h) compares well with recent estimates by Alvarez et. al.[38] (870 Mg/h) that were based on site-level measurements but utilized a different extrapolation approach incorporating parametrized nonlinear models.[39]"

A brief summary of the Alvarez study cited by Omara follows in Appendix B.

[37] Omara et. al (2018) - Methane Emissions from Natural Gas Production Sites in the United States: Data Synthesis and National Estimate. Environ. Sci. Technol. 2018, 52, Page 12915.
[38] R. A. Alvarez et. al. (June 2018): Assessment of methane emissions from the U.S. oil and gas supply chain. Science 10.1126/science.aar7204 (2018).
[39] Id. Page 12923.

Appendix B

Alvarez (EDF) et al. (June 2018): Assessment of methane emissions from the U.S. oil and gas supply chain[40]

The study reports on methane emissions estimated using ground-based, facility-scale measurements and validated with aircraft observations in areas accounting for roughly 30% of U.S. gas production. The Alvarez study indicated that: "When scaled up nationally, our facility-based estimate of 2015 supply chain emissions is 13 ± 2 Tg/y, equivalent to 2.3% of gross U.S. gas production. This value is ~60% higher than the U.S. EPA inventory estimate, likely because existing inventory methods miss emissions released during abnormal operating conditions.[41]" The study presents work that integrates the results of recent facility bottom-up (BU) measurements of CH_4 emissions. In BU studies, emissions from individual pieces of equipment, operations, or facilities taking directly at the site or downwind of the site are used to generate regional, state, or national methane emission estimates.

Table S1 of the article (page 35) lists data published since 2012 that reported source-specific emission measurements that comprised of 10 or more samples or used to characterize emissions from a population of sources. Table 1 includes measurements for several industry segments and source categories and certain datasets were not used in this work reported by Alvarez. For oil and natural gas production sites, the dataset includes sites in the Barnett Shale (reported in Rella 2015), Marcellus Shale (Omara 2016), Fayetteville/D-J/UGR/Unita (reported in Robertson 2017 and Brantley 2014), and other U.S. sites (reported in Allen 2013).

[40] R. A. Alvarez et. al. (June 2018): Assessment of methane emissions from the U.S. oil and gas supply chain. Science 10.1126/science.aar7204 (2018).
[41] Id. Page 1.

Table S2 of the article (page 36) presents the TD studies utilized for this study which include reported methane emissions from the oil and natural gas industry based on aircraft measurements between 2012-2015. Table S2 includes the "Fayetteville study" reported by Scwietzke et al.[42] summarized in Appendix C.

[42] Schwietzke (Univ. of CO), Petron (NOAA), et al. (2017): Improved Mechanistic Understanding of Natural Gas Methane Emissions from Spatially Resolved Aircraft Measurements. Environ. Sci. Technol. 2017, 51, 7286-7294.

Appendix C

Schwietzke (Univ. of CO), Petron (NOAA), et al. "Fayetteville Study" (2017): Improved Mechanistic Understanding of Natural Gas Methane Emissions from Spatially Resolved Aircraft Measurements[43]

The work reported in this article was part of a "comprehensive study to expand and improve the top-down vs bottom-up reconciliation effort by providing for the first time a spatially resolved aircraft-based midday CH_4 emission estimate for comparison with a temporally and spatially consistent bottom-up inventory.[44]" Due to reported discrepancies in recent methane studies based on aircraft measurements versus emissions inventories, an effort was undertaken to understand the different elements of the two measurement methodologies and how to interpret the results.

The study concluded that: "Our aircraft-based methane emission estimates in a major U.S. shale gas basin resolved from west to east show (i) similar spatial distributions for 2 days, (ii) strong spatial correlations with reported NG production (R2 = 0.75) and active gas well pad count (R2 = 0.81), and (iii) 2× higher emissions in the western half (normalized by gas production) despite relatively homogeneous dry gas and well characteristics. [45]" The study further concluded that: "Our study based on state of the science measurements, analysis, and access to industry operational data is unique and sheds new light on the interpretation of previous basin scale aircraft studies. The interpretation of previous short term, midday aircraft based CH_4 measurements has focused on comparison with annualized inventories. Some [studies] have employed statistical models to explain differences between top down and bottom-up estimates

[43] Schwietzke (Univ. of CO), Petron (NOAA), et al. (2017): Improved Mechanistic Understanding of Natural Gas Methane Emissions from Spatially Resolved Aircraft Measurements. Environ. Sci. Technol. 2017, 51, 7286-7294.
[44] Id. 7287.
[45] Id. 7286.

with the existence of super-emitters or unknown sources of emissions, i.e., fat tail emission distributions. We offer a different explanation by showing that manually triggered, episodic releases of NG can represent a large fraction (~1/3 in this case) of total midday CH_4 emissions.[46]"

[46] Id. 7292-7293.

MEMORANDUM

TO: EPA Docket ID No. EPA-HQ-OAR-2017-0483

DATE: February 27, 2020

SUBJECT: Equivalency of State Fugitive Emissions Programs for Well Sites and Compressor Stations to Standards at 40 CFR Part 60, Subpart OOOOa

---

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 final rule for the Oil and Natural Gas Sector New Source Performance Standards (NSPS) at 40 CFR Part 60, Subpart OOOOa, as amended in 2020.

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 granted reconsideration of several requirements 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). On October 15, 2018, the EPA proposed amendments to the 2016 NSPS OOOOa ("2018 Proposal"), including alternative fugitive emissions standards for well sites and compressor stations based on the EPA's determination that programs in California, Colorado, Ohio, Pennsylvania, Texas, and Utah were equivalent or better than the fugitive emissions requirements in the proposed amendments.

This memorandum details the process taken to evaluate equivalency of these existing programs, updates the evaluation based on public comments received on the 2018 Proposal and the requirements of the final rule, and provides determinations for alternative fugitive standards contained in the final rule. Section 3.0 provides a summary of the fugitive emissions requirements in the final rule. 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. Section 6.0 provides an evaluation of the reporting requirements for the six states with alternative fugitive emissions standards in the final rule. A summary of the conclusions of this analysis is included in section 7.0. Links to each of the programs evaluated in this analysis are provided in Appendix 1.

3.0 FUGITIVE EMISSIONS REQUIREMENTS IN NSPS OOOOa

NSPS OOOOa sets standards to control 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 with total site production greater than 15 barrels of oil equivalent (boe) per day and semiannual monitoring for fugitive emissions at compressor stations. Additionally, well sites (with total site production greater than 15 boe per day) and compressor stations located on the Alaska 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). A first attempt at repair must be made within 30 days of detection, with repairs completed, including a resurvey of the repaired component, within 30 days of the first attempt at repair using either OGI or Method 21. When using OGI for this resurvey, no visible emissions indicates successful repair. When using 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. Records of each fugitive emissions survey, including each component detected with fugitive emissions and repairs, must be kept. Specific information on each site-level fugitive emissions survey are required as part of the annual report for NSPS OOOOa.

A summary of the fugitive emissions requirements within NSPS OOOOa is provided in Table 1.

Table 1. Summary of Fugitive Emissions Requirements in NSPS OOOOa

	NSPS OOOOa	
Monitoring Instrument	OGI	Method 21
Leak Definition	Visible leak	500 ppm
Initial Monitoring		
- *Well Sites*	90 days	
- *Compressor Stations*		
Monitoring Frequency		
- *Well Sites*	Semiannual	
- *Low Production Wells*	Maintain total production <15 boe/day	
- *Compressor Stations*	Semiannual	
Repair		
- *First Attempt*	30 days of detection	
- *Final Repair*	30 days of first attempt, includes resurvey	
- *DOR Deadline*	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 final rule 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. We received comments on the 2018 Proposal that stated the reporting requirements for NSPS OOOOa should not apply to the states with approved alternative fugitive emissions standards. In response to these comments, this analysis also includes an examination of the recordkeeping and reporting requirements for the states with approved alternative fugitive emissions standards only. A summary of the evaluation of each of the programs is provided in section 5.0 and 6.0.

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 NSPS OOOOa, 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 NSPS OOOOa 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

[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

any additional information on this effort. Therefore, we are not able to evaluate equivalency of these requirements to NSPS OOOOa.

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.

[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 NSPS OOOOa 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	X
Connectors	X	X[8]	X		X	X	X	X	X	X
Covers	X	X			X	X	X		X	X
CVSs	X[9]	X			X	X	X		X	X
Flanges	X	X	X		X	X	X	X	X	X
Instruments	X	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	X			X
Thief Hatches	X	X	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, the EPA assumes all NSPS OOOOa components are included.
[6] Pennsylvania permit language does not list component types to be inspected. For this analysis, the EPA assumes all NSPS OOOOa 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 NSPS OOOOa:

Table 5. Equivalency of California's Fugitive Emissions Requirements to NSPS OOOOa

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*	Yes	
- *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 ozone nonattainment areas (Part D, section I.L) and one that covers the entire state (Part D, section II.E). A summary of these two sets of requirements is presented in Table 6.

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[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.colorado.gov/pacific/cdphe/aqcc-regs

Table 6. Summary of Fugitive Emissions Requirements in Colorado

Regulation	Regulation 7, Part D, Section I.L			Regulation 7, Part D, Section II.E		
Effective Date	February 14, 2020			February 14, 2020		
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 $\geq$ 1 and $\leq$ 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 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

<table>
<tr><td>Well Production Facilities without Storage Tanks (rolling 12-month tpy)</td><td>Well Production Facilities with Storage Vessels (rolling 12-month tpy)</td><td>Approved Instrument Monitoring Method Inspection Frequency</td><td>AVO Inspection Frequency</td><td>Phase-in Schedule</td></tr>
<tr><td>> 0 and < 2</td><td>> 0 and < 2</td><td>One time</td><td>Monthly</td><td>January 1, 2016</td></tr>
<tr><td>≥ 2 and ≤ 12</td><td>≥ 2 and ≤ 12</td><td>Semiannually</td><td>Monthly</td><td>*Begins in 2020</td></tr>
<tr><td>> 2 and < 12, located within 1,000 feet of an occupied area</td><td>> 2 and < 12, located within 1,000 feet of an occupied area</td><td>Quarterly</td><td>Monthly</td><td>*Begins in 2020</td></tr>
<tr><td>> 12 and ≤ 20</td><td>> 12 and ≤ 20</td><td>Quarterly</td><td>Monthly</td><td>January 1, 2015</td></tr>
<tr><td>> 12, located within 1,000 feet of an occupied area</td><td>> 12, located within 1,000 feet of an occupied area</td><td>Monthly</td><td></td><td>*Begins 2020</td></tr>
<tr><td colspan="5"></td></tr>
<tr><td colspan="2">Compressor Station Fugitive VOC emissions (rolling 12-month tpy)</td><td colspan="3">Frequency</td></tr>
<tr><td colspan="2">> 0 and ≤ 12</td><td colspan="3">Semiannually</td></tr>
<tr><td colspan="2">> 12 and ≤ 50</td><td colspan="3">Quarterly</td></tr>
<tr><td colspan="2">> 50</td><td colspan="3">Monthly</td></tr>
</table>

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 NSPS OOOOa.

[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

Table 10. Equivalency of Colorado's Fugitive Emissions Requirements to NSPS OOOOa

<table>
<tr><td>Regulation</td><td colspan="2">Regulation 7, Part D, § I.L</td><td colspan="2">Regulation 7, Part D, § II.E</td></tr>
<tr><td>Effective Date</td><td colspan="2">February 14, 2020</td><td colspan="2">February 14, 2020</td></tr>
<tr><td>Monitoring Instrument</td><td>OGI</td><td>Method 21</td><td>OGI</td><td>Method 21</td></tr>
<tr><td>Leak Definition</td><td>Yes</td><td>Yes</td><td>Yes</td><td>Yes</td></tr>
<tr><td>Initial Monitoring</td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>- Well Sites</td><td colspan="2">Yes</td><td colspan="2">Yes[16]</td></tr>
<tr><td>- Compressor Stations</td><td colspan="2">Yes</td><td colspan="2">Yes (> 50 tpy VOC emissions or constructed after January 1, 2015)</td></tr>
<tr><td>Monitoring Frequency</td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>- Well Sites</td><td colspan="2">Yes[17]</td><td colspan="2">Yes[18]</td></tr>
<tr><td>- Low Production Wells</td><td colspan="2">Yes (> 1 tpy uncontrolled VOC emissions)</td><td colspan="2">Yes[19]</td></tr>
<tr><td>- Compressor Stations</td><td colspan="2">Yes</td><td colspan="2">Yes (> 12 tpy fugitive VOC emissions)</td></tr>
<tr><td>Repair</td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>- First Attempt</td><td colspan="2" rowspan="4">Yes</td><td colspan="2" rowspan="4">Yes</td></tr>
<tr><td>- Final Repair</td></tr>
<tr><td>- Resurvey</td></tr>
<tr><td>- DOR Deadline</td></tr>
</table>

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.

[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 VOC emissions
[18] For sites w/ tanks: > 2 tpy VOC emissions from highest emitting tank, sites w/out tanks: > 2 tpy controlled VOC emissions
[19] Sites w/ tanks: > 2 tpy VOC emissions from highest emitting tank; for sites w/out tanks: > 2 tpy controlled VOC emissions
[20] Montana regulations available at http://deq.mt.gov/DEQAdmin/dir/legal/Chapters/ch08-toc.

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 NSPS OOOOa.

Table 12. Equivalency of Montana's Fugitive Emissions Requirements to NSPS OOOOa

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 NSPS OOOOa.

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 NSPS OOOOa. 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 NSPS OOOOa

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[a][27]
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 NSPS OOOOa.

Table 16. Equivalency of Ohio's Fugitive Emissions Requirements to NSPS OOOOa

<table>
<tr><td>Permit</td><td colspan="2">General Permits 12.1 and 12.2</td><td colspan="2">General Permit 18.1</td></tr>
<tr><td>Effective Date</td><td colspan="2">April 14, 2014</td><td colspan="2">February 7, 2017</td></tr>
<tr><td>Monitoring Instrument</td><td>OGI</td><td>Method 21</td><td>OGI</td><td>Method 21</td></tr>
<tr><td>Leak Definition</td><td>Yes</td><td>500 ppm – Yes</td><td>Yes</td><td>500 ppm - Yes</td></tr>
<tr><td>Initial Monitoring</td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>- Well Sites</td><td colspan="2">Yes</td><td colspan="2">NA</td></tr>
<tr><td>- Compressor Stations</td><td colspan="2">NA</td><td colspan="2">Yes</td></tr>
<tr><td>Monitoring Frequency</td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>- Well Sites</td><td colspan="2" rowspan="2">Yes, at least semiannual</td><td colspan="2" rowspan="2">NA</td></tr>
<tr><td>- Low Production Wells</td></tr>
<tr><td>- Compressor Stations</td><td colspan="2">NA</td><td colspan="2">Yes</td></tr>
<tr><td>Repair</td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>- First Attempt</td><td colspan="2" rowspan="3">Yes</td><td colspan="2" rowspan="4">Yes</td></tr>
<tr><td>- Final Repair</td></tr>
<tr><td>- Resurvey</td></tr>
<tr><td>- DOR Deadline</td><td colspan="2">No[29]</td></tr>
</table>

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

[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.

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 NSPS OOOOa.[30] We are not evaluating equivalency of the permit requirements for Oklahoma because the current requirements incorporate 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		

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

[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

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 NSPS OOOOa.

Table 18. Equivalency of Pennsylvania's Permit Fugitive Emissions Requirements to NSPS OOOOa

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 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

[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.
[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.

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 NSPS OOOOa. 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), [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" (Non-Rule Standard Permit).[37] 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)	Non-Rule Standard Permit		30 TAC § 116.620
Effective Date	February 27, 2011	November 8, 2012		September 4, 2000
Monitoring Instrument	(Not specified)	Method 21	OGI	Gas Analyzer
Leak Definition	NA	500 or 10,000 ppm	Visible leak	500, 2,000, or 10,000 ppm
Initial Monitoring				
- *Well Sites*	90 days	90 days		90 days
- *Compressor Stations*				
Monitoring Frequency				
- *Well Sites*	Quarterly, reduce to annual if % leaking valves is low	Quarterly, reduce to annual if % leaking valves is low		Quarterly, reduce to annual if % leaking valves is low
- *Low Production Wells*				
- *Compressor Stations*				
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

[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.

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 NSPS OOOOa. 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 NSPS OOOOa

<table>
<tr><td>Regulation/Permit</td><td>30 TAC § 106.352(e)(6)</td><td colspan="2">Non-Rule Standard Permit</td><td colspan="2">30 TAC § 116.620</td></tr>
<tr><td>Effective Date</td><td>February 27, 2011</td><td colspan="2">November 8, 2012</td><td colspan="2">September 4, 2000</td></tr>
<tr><td>Monitoring Instrument</td><td>(Not specified)</td><td>Method 21</td><td>OGI</td><td>Method 21</td><td>OGI</td></tr>
<tr><td>Leak Definition</td><td>No</td><td>500 ppm - Yes</td><td>Visible leak</td><td>500 ppm - Yes</td><td>Visible leak</td></tr>
<tr><td>Initial Monitoring</td><td></td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>- Well Sites</td><td>Yes</td><td colspan="2">Yes</td><td colspan="2">Yes</td></tr>
<tr><td>- Compressor Stations</td><td>Yes</td><td colspan="2">Yes</td><td colspan="2">Yes</td></tr>
<tr><td>Monitoring Frequency</td><td></td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>- Well Sites</td><td rowspan="2">No</td><td colspan="2" rowspan="2">Yes, at least semiannual</td><td colspan="2" rowspan="2">Yes, at least semiannual</td></tr>
<tr><td>- Low Production Wells</td></tr>
<tr><td>- Compressor Stations</td><td>No</td><td colspan="2">Yes, at least quarterly</td><td colspan="2">Yes, at least quarterly</td></tr>
<tr><td>Repair</td><td></td><td colspan="2"></td><td colspan="2"></td></tr>
<tr><td>- First Attempt</td><td rowspan="2">Yes</td><td colspan="2" rowspan="2">Yes</td><td colspan="2" rowspan="2">Yes</td></tr>
<tr><td>- Final Repair</td></tr>
<tr><td>- Resurvey</td><td>No</td><td colspan="2">No</td><td colspan="2">No</td></tr>
<tr><td>- DOR Deadline</td><td>Yes</td><td colspan="2">Yes</td><td colspan="2">Yes</td></tr>
</table>

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[38] 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.[39] A summary of Utah's fugitive emissions requirements is provided in Table 22.

Table 22. Summary of Fugitive Emissions Requirements in Utah

<table>
<tr><td>Regulation</td><td colspan="3">General Approval Order</td><td colspan="2">Utah Admin. Code r. 307-509</td></tr>
<tr><td>Effective Date</td><td colspan="3">June 5, 2014</td><td colspan="2">March 2, 2018</td></tr>
<tr><td>Monitoring Instrument</td><td>OGI</td><td>Method 21</td><td>TDLAS</td><td>OGI</td><td>Method 21</td></tr>
<tr><td>Leak Definition</td><td>Visible leak</td><td>500 ppm</td><td>500 ppm</td><td>Visible leak</td><td>500 ppm</td></tr>
<tr><td>Initial Monitoring</td><td colspan="3"></td><td colspan="2"></td></tr>
<tr><td>- Well Sites</td><td colspan="3">90 days</td><td colspan="2">60 days</td></tr>
<tr><td>- Compressor Stations</td><td colspan="3">NA</td><td colspan="2">NA</td></tr>
<tr><td>Monitoring Frequency</td><td colspan="3"></td><td colspan="2"></td></tr>
<tr><td>- Well Sites</td><td colspan="3" rowspan="2">Annual if production ≥ 10,000 bbl/a; Quarterly if production ≥ 25,000 bbl/a and storage vessel present.</td><td colspan="2" rowspan="2">Semiannual if uncontrolled storage tank and dehydrators emissions > 4 tpy VOC</td></tr>
<tr><td>- Low Production Wells</td></tr>
<tr><td>- Compressor Stations</td><td colspan="3">NA</td><td colspan="2">NA</td></tr>
<tr><td>Repair</td><td colspan="3"></td><td colspan="2"></td></tr>
<tr><td>- First Attempt</td><td colspan="3">5 days</td><td colspan="2">NA</td></tr>
<tr><td>- Final Repair</td><td colspan="3" rowspan="2">15 days</td><td colspan="2">15 days</td></tr>
<tr><td>- Resurvey</td><td colspan="2">30 days</td></tr>
<tr><td>- DOR Deadline</td><td colspan="3">Next shutdown, with final repair within 6 months</td><td colspan="2">Next shutdown or shut-in, after a vent blowdown, or within 2 years, whichever is earlier</td></tr>
<tr><td>- Additional DOR Info</td><td colspan="3">If parts are ordered, repair within 15 days of receipt</td><td colspan="2">Unsafe to repair during operation of the unit</td></tr>
</table>

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

[38] Utah General Approval Order available at http://www.deq.utah.gov/Permits/GAOs/docs/2014/6June/DAQE-AN149250001-14.pdf.
[39] Utah Admin. Code r. 307-509. Final rule text available at https://www.utah.gov/pmn/files/359797.pdf#page=2

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[40] 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 NSPS OOOOa. 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.

[40] As defined in Utah Admin. Code r. 307-101-2

Table 23. Equivalency of Utah's Fugitive Emissions Requirements to NSPS OOOOa

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.[41] 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 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

[41] 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.[42] 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 NSPS OOOOa. However, due to the flexibility of the requirements, we are unable to include alternative fugitive standards relative to these requirements.

[42] Wyoming regulations are available at https://rules.wyo.gov/.

Table 25. Equivalency of Wyoming's Fugitive Emissions Requirements to NSPS OOOOa

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 ANALYSIS OF STATE FUGITIVE EMISSIONS REPORTING REQUIREMENTS

After determining which states had fugitive emissions standards that are equivalent or better than the NSPS OOOOa requirements, we reviewed the recordkeeping and reporting requirements to determine if reporting should be limited to state-only reporting or if reporting through NSPS OOOOa was still necessary. This review was a result of public comments that were received on the 2018 Proposal. The specific recordkeeping and reporting requirements for fugitive emissions requirements are found in §60.5420a(c)(15) and §60.5420a(b)(7), respectively.

As part of this review, the EPA first examined what information is reported at the site-level for each of the state programs considered equivalent in order to determine if the information would sufficiently demonstrate compliance with the standards. Where site-level reporting is not required by the state, the EPA examined what information is necessary to determine compliance with the approved alternative fugitive emissions standard. Regardless of the determination of whether the state-required report is sufficient for demonstrating compliance with the alternative fugitive emissions standards, it is important that the EPA receive information through the annual report for compliance purposes. Therefore, the final rule requires the following in the annual report for the alternative fugitive emissions standards:

(1) the site-level report required by the specific state, attached to the electronic report for NSPS OOOOa, in the format in which it is submitted to the state; or

(2) if site-level reporting is not provided to the state, submit the required electronic report for NSPS OOOOa. Whenever possible, the EPA would prefer the information in option (1) is sent in the XML format rather than receiving PDF versions so that the data can be utilized more efficiently.

6.1 California

California provides recordkeeping and reporting forms for their LDAR inspections. These forms are located in Appendix A, Tables 4 and 5 of the California Code of Regulations, Title 17, Division 3, Chapter 1, Subchapter 10 Climate Change, Article 4.[43]

Table 4 of Appendix A of the regulation requires the following information to be recorded and reported for each monitoring survey:

- Inspection Date
- Facility Name
- Air District
- Owner/Operator Name
- Address
- Contact Person (including Phone)
- Inspection Company Name
- Number of Leak Per Leak Threshold Category (*i.e.,* 1,000 – 9,999 ppmv, 10,000 – 49,999 ppmv, and 50,000 ppmv or greater)
- Percentage of Total Components Inspected within Each Category
- Total Components Inspected

Table 4 also requires signature attesting the person is authorized to sign the form and that the information provided is true and correct.

Table 4 of Appendix A of the regulation requires the following information to be recorded and reported for each leak and repair during each monitoring survey:

- Inspection Date
- Facility Name
- Air District
- Owner/Operator Name
- Address
- Contact Person (including Phone)
- Inspection Company Name
- Method 21 Instrument Make/Model
- Instrument Calibration Date

[43] https://ww2.arb.ca.gov/sites/default/files/2018-06/2017%20Final%20Reg%20Orders%20GHG%20Emission%20Standards.pdf

- Component Type, Initial Leak Concentration (ppmv), Repair Date, and Concentration After Repair (ppmv) for each Component Identified as Leaking

Table 5 also requires signature attesting the person is authorized to sign the form and that the information provided is true and correct.

California requires electronic reporting of the information in Tables 4 and 5 of Appendix A of the regulation. This reporting is required annually through the electronic reporting platform e-GGRT. At the time of this analysis, the web-based system was in its final development phase. In the interim, the reporting is required through electronic spreadsheets that are provided by the state. We have concluded the reports are sufficient for determining compliance with the alternative fugitive emissions standard for well sites and compressor stations located in California and NSPS OOOOa requires that owners and operators adopting the alternative fugitive emissions standards to attached a copy of these reports to the annual electronic reporting submission for NSPS OOOOa in the format in which they are submitted to California.

6.2 Colorado

Colorado provides recordkeeping and reporting forms for their LDAR inspections. We reviewed the December 2018 version[44] of the reporting form and the January 2019 version[45] of the recordkeeping form for this analysis.

The LDAR Annual Report Form is a fillable PDF document that requires the following information:

- Company Name
- Inspection Year
- Contact Person, including Title, Phone, and E-mail
- Number of Well Production Facilities Inspected
- Number of Compressor Stations Inspected
- Information by Type of Inspection (*e.g.,* AVO, Method 21, OGI, AIMM):
  - Number of leaks, repairs, and delayed repairs by component type
  - For delayed repairs, indication of parts orders, shutdown needed, or other information

This form is electronically submitted to the state for reporting purposes through email. The reporting, however, is aggregated for all sites within a specific company rather than by individual site, therefore, the reports required by Colorado are insufficient for demonstrating compliance with the alternative fugitive emissions standards for Colorado.

The recordkeeping form requires the following information to be kept in the record for each individual monitoring survey:

- Facility Name

[44] https://environmentalrecords.colorado.gov/HPRMWebDrawer/RecordView/1272496
[45] https://environmentalrecords.colorado.gov/HPRMWebDrawer/RecordView/1283417

- Facility Type (well site or compressor station)
- Facility AIRS ID
- Location (decimal degrees)
- Date of Inspection
- Name of Person Completing Inspection
- Inspection Method (*e.g.,* AVO, Method 21, OGI, AIMM)
- Inspection Type (*e.g.,* Initial AIMM, Periodic AIMM, AVO)
- AIMM Inspection Frequency (*e.g.,* monthly, quarterly, semiannual, annual, one-time)
- Details of Leaking Components:
    - Component ID, Component Type
    - Date of 1st Attempt at Repair
    - Date of Additional Repair Attempts
    - Date of Successful Repair
    - Repair Method Applied (chosen from list of options)
    - Date(s) of Remonitoring
    - Result(s) of Remonitoring
    - Indication of Delayed Repair (and associated information on delay)
    - Unsafe, Difficult, or Inaccessible to Monitor

In this instance, the EPA reviewed these recordkeeping requirements for Colorado. The information required for the annual report for fugitive emissions in NSPS OOOOa is required in the recordkeeping for Colorado Regulation 7. Therefore, sites in Colorado that adopt the alternative fugitive emissions standards are required to submit the information required in NSPS OOOOa in the annual report.

6.3 Ohio

General Permits 12.1, 12.2, and 18.1 require reporting through an annual Permit Evaluation Report (PER) with a Supplement to the PER for the LDAR program.[46] This supplemental report includes the following information:

- Date of the Inspection
- Number of Components Determined to be Leaking
- Company ID and Component Type for Each Leaking Component
- Total Number of Components at the Site
- Percent of Components Determined to be Leaking
- List of all Components with Delayed Repair and a Reason for the Delay
- Notification if Future Inspection Frequencies Change Based on Percent Leaking

[46] https://epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.1_PTIOA20140403final.pdf, https://epa.ohio.gov/Portals/27/oil%20and%20gas/GP12.2_PTIOA20140403final.pdf, and https://www.epa.ohio.gov/Portals/27/genpermit/GP18.1_F20170210.pdf

Ohio requires reportingthrough electronic submission of the PER online at the Ohio EPA's e-Business Center: Air Services as a fillable PDF or allows owners and operators to submit a physical copy of the form either by mail or through hand delivery. This report contains information sufficient to determine site-level compliance with the alternative fugitive emissions standards for Ohio. Therefore, sites that adopt the alternative fugitive emissions standards are required to submit to the EPA the report, in the format submitted to Ohio, with one exception. The EPA is requiring that reports are submitted electronically and will not accept hard copies. If a hard copy is submitted to the state, the owner or operator must provide the report electronically to the EPA.

6.4 Pennsylvania

Pennsylvania General Permits 5 and 5A[47] require the reporting of the records of each monitoring survey conducted during that reporting period. These records include the following information consistent with the 2016 NSPS OOOOa:

- Facility Name and Location
- GP-5 Authorization Number
- Date, Start Time, and End Time of Survey
- Name of Operator(s) Performing the Survey
- Monitoring Instrument Used
- Ambient Temperature, Sky Conditions, Maximum Wind Speed
- Any Deviations from the Monitoring Plan
- Documentation of Each Fugitive Emission, including Repairs and Resurveys

The state of Pennsylvania requires an online fillable form to be completed through either the AES*Online or AES*XML platforms. This report contains information sufficient to determine site-level compliance with the alternative fugitive emissions standards for Pennsylvania. Therefore, sites that adopt the alternative fugitive emissions standards are required to submit to the EPA the report required by General Permits 5 and 5A, in the format submitted to Pennsylvania.

6.5 Texas

The Texas Administrative Code, Title 30, Part 1, Chapter 116, Subchapter F, Rule §116.620 requires records for the results of the LDAR requirements.[48] These records include the following information:

- Appropriate Dates
- Test Methods
- Instrument Readings

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[47] http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=36119, and http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=36120

[48] https://texreg.sos.state.tx.us/public/readtac$ext.TacPage?sl=T&app=9&p_dir=F&p_rloc=86097&p_tloc=14963&p_ploc=1&pg=3&p_tac=&ti=30&pt=1&ch=116&rl=

- Repair Results
- Corrective Actions.

Based on the EPA's review of requirements, reporting if required only when leaks occur, and regular reporting outside of a fugitive emissions event is not required. The EPA reviewed the recordkeeping requirements for Texas. The information required for the annual report for fugitive emissions in NSPS OOOOa is required in the recordkeeping for Texas. Therefore, sites in Texas that adopt the alternative fugitive emissions standards are required to submit the information required in NSPS OOOOa in the annual report.

6.6 Utah

The requirements for well sites in Utah are included in Utah Administrative Code, Rule R307-509, Oil and Gas Industry: Leak Detection and Repair Requirements.[49] Utah does not require reporting of fugitive emissions, but does require specific records of the fugitive emissions survey in the requirements at Utah Administrative Code R307-509-5. The recordkeeping requirements specify the owner or operator maintains records of (1) the emissions monitoring plan and (2) the monitoring surveys, repairs, and resurveys.

The monitoring plan requires, at a minimum, the following information:

- Monitoring Frequency
- Monitoring Technique and Equipment
- Procedures and Timeframes for Identifying and Repairing Leaks
- Recordkeeping Practices
- Calibration and Maintenance Procedures for Monitoring Equipment
- Difficult-to-Monitor and Unsafe-to-Monitor Components

As discussed in Section 5.12, the requirements for the monitoring survey are equivalent or better than those in NSPS OOOOa. While the recordkeeping requirement is general to "maintain records of the surveys, repairs, and resurveys," the EPA has concluded that the information required for the annual report for fugitive emissions in NSPS OOOOa is required in the recordkeeping for Utah. Therefore, sites in Utah that adopt the alternative fugitive emissions standards are required to submit the information required in NSPS OOOOa in the annual report.

7.0 CONCLUSIONS

Based on the analysis presented in section 5.0 and 6.0, 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, Part D, §§I.L or II.E, effective February 14, 2020;
- Ohio General Permits 12.1 and 12.2, effective April 14, 2014;
- Ohio General Permit 18.1, effective February 7, 2017;

[49] https://rules.utah.gov/publicat/code/r307/r307-509.htm#T5

- Pennsylvania General Permits 5 and 5A, 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 NSPS OOOOa or do not have requirements that we were able to evaluate:

- Alaska
- Oklahoma
- West Virginia

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration 40 CFR Part 60, subpart OOOOa

Response to Public Comments on

Proposed Rule [83 FR 52056, October 15, 2018]

Comments, letters, and transcripts of the public hearings are also available electronically through *http://www.regulations.gov* by searching Docket ID EPA-HQ-OAR-2017-0483

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FOREWORD

This document provides the EPA's responses to public comments on the EPA's Proposed *Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration*. The EPA published a Proposed Rule in the *Federal Register* on October 15, 2018, at 83 FR 52056. The EPA received comments on this proposed rule via mail, e-mail, facsimile, and two concurrent public hearings held in Denver, CO in November 2018. Copies of all comments and transcripts for the public hearing are available at the EPA Docket Center Public Reading Room. Out of an abundance of caution for members of the public and our staff, the EPA Docket Center and Reading Room was closed to public visitors on March 31, 2020, to reduce the risk of transmitting COVID-19. Our Docket Center staff will continue to provide remote customer service via email, phone, and webform while the EPA Docket Center and Reading Room are closed. Comments and transcripts of the public hearing are also available electronically through http://www.regulations.gov by searching Docket ID EPA-HQ-OAR-2017-0483. For further information and updates on EPA Docket Center services and the current status, please visit us online at https://www.epa.gov/dockets.

Just under 509,000 public comments were received on the proposal. The EPA Docket Center consolidated mass mail campaigns and petitions into single document control numbers (DCNs), resulting in over 2,100 unique comments. Each of these comments was reviewed and significant comments relevant to this action and submitted within the comment period have been summarized and included in this document.

It is possible some responses in the Response to Comments Document may not reflect the language in the preamble and final rule in every respect. Where the response conflicts with the preamble or the final rule, the language in the final preamble and rule controls and should be used for purposes of understanding the scope, requirements, and basis of the final rule. The responses presented in this document are intended to augment the responses to comments that appear in the preamble to the final rule or to address comments not discussed in that preamble. Although portions of the preamble to the final rule are paraphrased in this document where useful to add clarity to responses, the preamble itself remains the definitive statement of the rationale for the revisions adopted in the final rule. In many instances, responses presented in the Response to Comments Document include cross references to responses on related issues that are located either in the preamble or elsewhere in the Response to Comments Document. Accordingly, the Response to Comments Document, together with the preamble and final rule, and the rest of the administrative record should be considered collectively as the Agency's response to all the significant comments submitted on the proposed rule.

Table of Contents

ACRONYMS AND ABBREVIATIONS

ACE	Affordable Clean Energy
AEO	Annual Energy Outlook
AERs	Air Emission Reports
AIMM	Approved Instrument Monitoring Method
ALEC	American Legislative Exchange Council
AMEL	Alternate Means of Emission Limitation
APA	Administrative Procedures Act
APCD	Air Pollution Control District
APEEP	Air Pollution Emission Experiments and Policy
API	American Petroleum Institute
AQCC	Air Quality Control Commission
ARB	Air Resources Board
AVO	audio, visual and olfactory
AWP	Alternate Work Practice
B/D	barrels per day
BACT	Best Available Control Technology
BAT	Best Available Technology
BLM	Bureau of Land Management
BMP	Best Management Practices
boe	barrels of oil equivalent
BOED	barrels of oil equivalent per day
BP	British Petroleum
BPD	barrels per day
BSER	Best System of Emission Reduction
BU	bottom-up
CAA	Clean Air Act
CAM	Compliance Assurance Monitoring
CAMS	Collaboratory to Advance Methane Science
CAMx	Comprehensive Air Quality Model with Extensions
CAPP	Canadian Association of Petroleum Producers
CAQCC	Colorado Air Quality Control Commission
CARB	California's Air Resources Board
CBI	Confidential Business Information
CCAC	Climate and Clean Air Coalition
CDPHE	Colorado Department of Public Health and Environment
CE	control efficiency
CEDRI	Compliance and Emissions Data Reporting Interface
cfm	cubic feet per minute
CFR	Code of Federal Regulations
CH_4	methane
CMAQ	Congestion Mitigation and Air Quality
Co	Company
CO	Colorado
CO	carbon monoxide

CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
CO_2 Eq.	carbon dioxide equivalent
COPD	chronic obstructive pulmonary disease
CPF	Central Processing Facility
CPI	Consumer Price Index
CPIN	CPI of the date of original construction of the process unit
CPIPD	the most recently available CPI of the date of the project
CPI-U	Consumer Price Index for all urban consumers
CPP	Clean Power Plan
CRSD	Center for Responsible Shale Development
CS	compressor station
CTG	Control Techniques Guidelines
CVS	closed vent system
D&T	Drill and Tap
D.C.	District of Columbia
DCNs	Document Control Numbers
DEP	Department of Environmental Protection
DEQ	Department of Environmental Quality
DI&M	Directed Inspection and Maintenance
DICE	Dynamic Integrated Climate-Economy
DOE	Department of Energy
DOI	Department of Interior
DOR	delay of repair
DTM	difficult-to-monitor
EAV	Equivalent Annualized Value
EASIUR	Estimating Air Pollution Social Impact Using Regression
EDF	Environmental Defense Fund
EIA	Economic Impact Analysis
EIA	Energy Information Administration
EID	Energy In Depth
EGUs	Electric Generating Units
eNGO	environmental nongovernmental organization
EO	Executive Order
EPA	Environmental Protection Agency
E&P	exploration and production
FAA	Federal Aviation Administration
FCC	Federal Communications Commission
FEAST	Fugitive Emissions Abatement Simulation Testbed
Fed. Reg.	Federal Register
FEM	fugitives emissions monitoring
FERC	Federal Energy Regulatory Commission
FIP	Federal Implementation Plan
FLIR	Forward-looking Infrared
FOIA	Freedom of Information Act
FR	Federal Register

FUND	Framework for Uncertainty, Negotiation and Distribution
FW Study	Fort Worth Air Quality Study
GDP	gross domestic product
GHG	greenhouse gases
GHGI	greenhouse gas inventory
GHGRP	Greenhouse Gas Reporting Program
GOR	gas-to-oil ratio
GP	General Permit
GPA	GPA Midstream
GRI	Gas Research Institute
GWP	global warming potential
G&B	gathering and boosting
HAP	hazardous air pollutant(s)
HQ	Headquarters
hr	hour
H_2O	water
IAMs	Integrated Assessment Models
ICF	ICF International
ICR	Information Collection Request
ID	Identification
Inc.	Incorporated
INGAA	Interstate Natural Gas Association of America
InMAP	Intervention Model for Air Pollution
IPAA	Independent Petroleum Association of America
IPCC	Intergovernmental Panel on Climate Change
IR	infrared
IRS	Internal Revenue Service
IT	Information Technology
ITRC	Interstate Technology and Regulatory Council
IWG	Interagency Working Group
Kg	kilograms
KRU	Kuparuk River Unit
kt	kilotons
LACT	lease automatic custody transfer
LDAR	leak detection and repair
MACT	maximum achievable control technology
mcfd	thousand cubic feet per day
MDC	Methane Detectors Challenge
ME	Mechanical Engineering
METEC	Methane Emissions Test and Evaluation Center
MJB	MJ Bradley & Associates
MMT	Million Metric Tons
MONITOR	Methane Observation Networks with Innovative Technology to Obtain Reductions
MP	Model Plant
NAAQS	National Ambient Air Quality Standards

NAPSR	National Association of Pipeline Safety Regulatory
NAS	National Academy of Sciences
NASA	National Aeronautics and Space Administration
NCA	National Climate Assessment
ND	North Dakota
NEPA	National Environmental Protection Act
NERC	North American Electric Reliability Corporation
NESHAP	National Emission Standards for Hazardous Air Pollutants
NFPA	National Fire Protection Association
NGCC	Natural Gas Combined Cycle
NGLs	natural gas liquids
NGOs	Nongovernmental Organizations
NHTSA	National Highway Traffic Safety Administration
NOAA	National Oceanic and Atmospheric Administration
NODA	Notice of Data Availability
NO_X	nitrogen oxides
NPV	Net Present Value
NSPS	New Source Performance Standards
NSR	New Source Review
NW	Northwest
OAQPS	Office of Air Quality Planning and Standards
OAR	Office of Air and Radiation
ODNR	Ohio Department of Natural Resources
OECA	Office of Enforcement and Compliance Assurance
OELs	open-ended lines
OEM	original equipment manufacturer
OGCI	Oil & Gas Climate Initiative
OGI	optical gas imaging
OIRA	Office of Information and Regulatory Affairs
OMB	Office of Management and Budget
O&G	Oil & Gas
PAC	Political Action Committee
PAGE	Policy Analysis of the Greenhouse Effect
PBACT	Presumptive BACT
PBR	Permit by Rule
PBU	Prudhoe Bay Unit
PE	professional engineer
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIOGA	Pennsylvania Independent Oil & Gas Association
PM	particulate matter
PM2.5	PM with a diameter of 2.5 micrometers or less; fine particulate
POTW	Publicly Owned Treatment Works
ppm	parts per million
ppmv	part per million by volume
PRCI	Pipeline Research Council International
PRD	pressure relief device

PRV	pressure relief valve
PSD	Prevention of Significant Deterioration
psi	pound per square inch
psig	pound-force per square inch
PTE	potential to emit
PV	Present Value
QA/QC	Quality Assurance/Quality Control
qtr	quarter
RACT	reasonably available control technology
RAGA	Republican Attorney Generals Association
REC	Reduced Emission Completion
RIA	Regulatory Impact Analysis
RSLC	Republican State Leadership Committee
RTC	Response to Comments
R&D	Research and Development
SAB	Science Advisory Board
SCC	social cost of carbon
SC-CH4	social cost of methane
SC-CO2	social cost of carbon dioxide
SCF	Significant Contribution Finding
scfh	standard cubic feet per hour
SC-IAM	social cost of carbon IAMs
SI	Supporting Information
SIP	State Implementation Plan
SJVUAPCD	San Joaquin Valley Unified Air Pollution Control District
SoCal	Southern California
SOCMI	Synthetic Organic Chemical Manufacturing Industry
SWD	saltwater disposal
TAC	Texas Administrative Code
TCEQ	Texas Commission on Environmental Quality
TES	Target Emission Services
tpy	tons per year
TSD	Technical Support Document
TX	Texas
UARG	Utility Air Regulatory Group
UCLA	University of California Los Angeles
UIC	Underground Injection Control
UN	United Nations
U.S.	United States
U.S.C.	United States Code
USGCRP	United States Global Climate Research Program
UT	Utah
UTM	unsafe-to-monitor
VOC	volatile organic compounds
VRU	vapor recovery unit
WCCA	Wyoming County Commissioners Association

WGA	Western Governors' Association
WOTUS	Waters of the United States
WS	well site
WY	Wyoming
yr	year

Chapter 8. FUGITIVE EMISSIONS FROM WELL SITES AND COMPRESSOR STATIONS

This Chapter addresses the EPA's responses to public comments on the proposed reconsideration amendments for the collection of fugitive emissions components located at well sites and the collection of fugitive emissions components located at compressor stations. Commenters use the term "fugitive emissions" and "leak detection and repair (LDAR)" interchangeably, but this Chapter focuses on fugitive emissions from well sites and compressor stations, while another chapter focuses on traditional LDAR with Method 21 at natural gas processing plans (see Chapter 11 of this Responses to Comments (RTC) document).

Sections 8.1 and 8.2 of this Chapter focus on comments regarding appropriate monitoring frequencies at well sites (including low production well sites) and compressor stations, respectively. Section 8.3 reflects comments regarding modifications that trigger the fugitive emissions requirements. Section 8.4 discusses comments regarding the initial monitoring survey requirement, while Section 8.5 discusses the low temperature waiver for compressor stations subject to semiannual monitoring. Section 8.6 reflects comments received on the repair requirements, including delay of repair provisions. Section 8.7 reflects comments received on various definitions related to the fugitive emissions requirements. Section 8.8 reflects comments received on the fugitive emissions monitoring plan, and Section 8.9 discusses comments specific to the recordkeeping and reporting requirements.

8.1 Well Site

8.1.1 Well Sites

8.1.1.1 Need for Fugitive Emissions Program at Well Sites

Comment: Commenters express general support for the need for programs to reduce fugitive emissions at well sites. One commenter (0748) indicates that inspections in Boulder County Colorado show the need for LDAR to reduce ozone emissions. Boulder County Public Health has had a voluntary oil and gas inspection program in place since 2014 and has conducted more than 600 site visits to date. The commenter notes that the inspection program has created working relationships with operators that have producing well sites in Boulder County, identified issues in the field that were then addressed by the operators for safer and more efficient operations while reducing emissions, and informed the Boulder County Commissioners and staff during recent updates to local oil and gas regulations. The commenter provides that there has not been new oil production in Boulder County since 2012; hence, most well sites are older and low producing.

Commenter (0748) states that a 2017 white paper was prepared that analyzed data collected with an Infrared camera for gas leak detection at 145 facilities serving just over 300 wells from 2014-2016. The analysis found that in nearly 40 percent of the visits, a gas release was identified and communicated to the operator, who then took corrective actions to stop the release.

EPA clarify the assumptions concerning the GHGRP emission factors and how they account for the super leaker phenomenon.

Response: As explained in the TSD for this final rule, the model plants do not use GHGRP emission factors to estimate fugitive emissions. Instead, the emission factors developed in the 1995 EPA Emission Protocol document were used to estimate baseline emissions. While these emissions do not account for "super leakers," and are therefore consistent with most research, which indicates that this phenomenon is the result of a malfunction, and not a typical fugitive emission. Regarding low production well sites, the available information suggests that large sources of emissions are associated with storage vessels, including vented emissions. Where these storage vessels have potential VOC emissions exceeding 6 tons per year (tpy), the storage vessels must be controlled to reduce emissions by 95%.

Comment: Commenter (2041) asserts that EPA utterly ignores new scientific evidence that indicates the Agency has dramatically underestimated methane emissions from oil and gas production, and therefore underestimated the benefits of frequent monitoring. The commenter contends that minor (and unsupportive and irrelevant) uncertainties alleged by EPA are dwarfed by the extensive evidence showing that EPA has underestimated methane emissions from the oil and gas sector and therefore underestimated the emission reductions achieved by the 2016 NSPS OOOOa.

In support of these claims, commenter (2041) cites a recent study that synthesized previously published data to quantify methane emissions across the oil and gas supply chain, published in June 2018 in Science ("Synthesis") found that methane emissions from the sector were 60 percent higher than estimated by EPA's inventory[100]:

> Methane emissions from the U.S. oil and natural gas supply chain were estimated by using ground-based, facility-scale measurements and validated with aircraft observations in areas accounting for ~30% of U.S. gas production. When scaled up nationally, our facility-based estimate of 2015 supply chain emissions is 13 ± 2 teragrams per year, equivalent to 2.3% of gross U.S. gas production. This value is ~60% higher than the U.S. Environmental Protection Agency inventory estimate, likely because existing inventory methods miss emissions released during abnormal operating conditions. Methane emissions of this magnitude, per unit of natural gas consumed, produce radiative forcing over a 20-year time horizon comparable to the CO_2 from natural gas combustion. Substantial emission reductions are feasible through rapid detection of the root causes of high emissions and deployment of less failure-prone systems.[101]

Commenter (2041) asserts that evidence from the "Synthesis" strongly indicates that EPA has underestimated methane emissions at oil and gas facilities, and therefore underestimated the emission reductions achieved by the current NSPS. According to the commenter, it would be arbitrary and capricious for EPA to not fully evaluate this evidence and account for it when revising the standards. Furthermore, the commenter states that the "Synthesis" postulates that

[100] Alvarez et al. The Synthesis and supporting materials have been submitted in the regulatory docket for this rulemaking.
[101] Id. at 1.

(eNGOs) manipulate the data to create illusions of high emissions, these conclusions are no more valid than the estimates that the eNGOs criticize. Moreover, the commenter states that these data are based on facilities that largely preceded the requirements of NSPS OOOO and therefore do not reflect the technologies required by those regulations and their emission reductions.

Response: As summarized in comments above, in Section 8.1.2.6, and in other sections of this RTC, the EPA received several comments on the proposed baseline fugitive emissions estimates. One set of commenters critique the EPA's well site model plant analysis claiming that the EPA has underestimated well site fugitive emissions and consequently overestimated the cost-effectiveness of various monitoring frequencies. These commenters provided multiple studies and analyses in support of their claims that the EPA's has underestimated baseline fugitive well site emissions.[121] These commenters rely on those studies and reports to show that the EPA has not accurately estimated the forgone emission reductions associated with the proposed rule. These commenters use a variety of facility-level downwind measurement-based studies as the main basis to argue that increased monitoring frequency is necessary. The commenters also develop their own model plant baseline emissions based on those studies, and further use those emissions to conduct their own cost-effectiveness analysis for non-low and low production well sites.

Another set of commenters argue the opposite that the EPA has overestimated well site fugitive emissions and these commenters submitted their own set of supporting analyses. These commenters believe that the EPA has overestimated emissions for well sites. These commenters additionally claim, as described in the summary of comments above, that the numerous studies submitted by commenter 2041 and others contain several concerns and issues, and that overall downwind studies can overestimate total emissions and are not appropriate.

The EPA reviewed and considered the information provided by all commenters and presented the results of that review in a memorandum.[122] The EPA responds to what it believes are the key issues related to estimates of baseline fugitive emissions from both sides.

The EPA reviewed the study cited by commenter (2041) (plus a number of other studies submitted by commenter 2041) and documented the results of that review in a memorandum.[123] Overall, the EPA is not convinced that information provided in the multiple studies submitted by commenter (2041) is appropriate to rely on for this rulemaking due to a number of issues observed in those studies, as discussed in the following paragraphs. Therefore, the EPA was not able to directly use that information to update baseline fugitive emissions.

In particular, the EPA agrees with industry's concern that because the studies use remote measurements that include emissions from all sources at the site, including permitted emissions, it is not appropriate to rely on such measurements. Downwind total site emissions studies are not appropriate when evaluating fugitive emissions because there are several allowable or unregulated emissions sources located on these same sites. Where component-level fugitive

[121] See EPA-HQ-OAR-2017-0483-2041 and EPA-HQ-OAR-2017-0483-2194, and their associated appendices.
[122] Memorandum. Summary of Data Received on the October 15, 2018 Proposed Amendments to 40 CFR Part 60, Subpart OOOOa Related to Model Plant Fugitive Emissions. February 10, 2020.
[123] Id..

emissions are not quantified, it is not possible to differentiate those allowable or unregulated emissions from fugitive emissions.

Further, in the Assessment of Studies and Omara Appendix G report that the commenter (2041) submitted for the 2018 proposal, the commenter makes an unsupported assumption that 50 percent of total emissions measured at each site is attributed to fugitive emissions. According to the commenter (2041), the 50 percent estimate of fugitive emissions was made using data from the FW Study, however, neither industry, nor the EPA was able to reproduce this estimate. As stated, the EPA believes there is considerable uncertainty related to the 50% assumption. The FW Study only looked at specific emissions types and sitewide methane emissions were the result of fugitive components and tanks. Therefore, for sites without storage vessels, the only measured emissions were from fugitives meaning that 100% of the sitewide emissions were characterized as fugitive emissions. Including this 100% estimate of fugitive emissions in determining the average fraction of fugitive emissions across all sites therefore skews the results. Based on this methodology, the 50% assumption is not correct. Moreover, other sources consulted indicate that fugitive emissions are far less than that estimated by commenter (2041) (*e.g.,* based on the 2017 GHGRP the EPA found that out of the total reported methane emissions for all onshore production emissions sources only 18% were reported for equipment leaks). Studies cited by American Petroleum Institute (API), indicate that fugitive emissions could represent an even smaller portion of total sitewide emissions. For these reasons, the 50 percent estimate is not supported and there is considerable uncertainty related to the broad assumption that around 50 percent of these total emissions are fugitive emissions. Section 8.1.2.6 of this RTC describes industry's key issues with the commenter's (2041) submittals as it relates to fugitive emissions and the conclusions made.

The EPA did not adjust the final rule well site model plants based on the data received due to the limitations and uncertainties described above and more importantly because limited detail related to component counts were provided. Although data provided in comments were not sufficient to directly modify well site model plants, the EPA did re-examine the FW Study data as a result of the comments with respect to the low production model plant. This re-examination lead to a reduction in the number of low production model plant components and subsequently a reduction in the baseline emissions estimate of methane from 4.8 tpy at proposal to 3.5 tpy for the final rule low production gas well model plant. A summary of how the EPA used the FW Study for this rulemaking is provided in response to comments in Section 8.1.2.1 of this RTC and in a memorandum available from the docket where the EPA fully characterizes the FW Study analysis of fugitive emissions.[124] As discussed in the proposal and final rule preambles, the EPA evaluated other information outside of the FW Study in an effort to compare low and non-low production well sites. The FW Study remains the best source of information of equipment counts for developing the low production model plant, and as discussed in detail in Section 2.3.3 of the TSD, for estimating emissions, the EPA continues to believe that the component-based emission factors from the 1995 Protocol are appropriate.

After reviewing the information provided by all commenters, the EPA updated the model plants and concluded that semiannual monitoring of non-low production well sites remains cost-

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[124] Memorandum. Analysis of Low Production Well Site Fugitive Emissions from the Fort Worth Air Quality Study. May 18, 2018. EPA-HQ-OAR-2017-0483-0037.

include: failures of tank control systems, malfunctions upstream of the point of emissions (for example, stuck separator dump valve resulting in produced gas venting from tanks), design failures (for example, vortexing or gas entrainment during separator liquid dumps) and equipment or process issues (for example, over-pressured separators, malfunctioning or improperly operated dehydrators or compressors)." According to the commenter, these examples of abnormal process conditions are potential malfunction-related scenarios that could result in venting events. As acknowledged in the Zavala-Araiza, et al. paper, the commenter contends that these potential venting scenarios are NOT and should not be characterized as fugitive emissions. The commenter states that the EPA clearly appreciates this aspect as demonstrated in the definition of fugitive emission component under NSPS OOOOa; however, studies in the literature continue to confuse the issue.

Commenter (2237-L) highlights that some studies have examined malfunctioning intermittent bleed pneumatic controllers as a possible fugitive emission source. However, the commenter states that, as noted in the definition of fugitive emission component under NSPS OOOOa and in the "Small Entity Compliance Guide for Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources 40 CFR Part 60, Subpart OOOOa"[162], pneumatic devises are not fugitive emissions sources. The commenter cites the Small Entity Compliance Guide as stating:

> Fugitive emissions means any visible emission from a fugitive emissions component observed using OGI or an instrument reading of 500 ppm or greater using Method 21. Fugitive emissions component means any component that has the PTE 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.*

For additional perspective, commenter (2237-L) states that it is also helpful to consider emissions from other authorized (permitted), but non-fugitive, sources on a well pad relative to the emissions from fugitive sources. For example, the commenter notes that continuous low bleed pneumatic devices (*i.e.,* those that operate at 6 SCF/hr bleed rate) and certain storage vessels (those with less than 6 tons/year VOC emissions) are permitted under NSPS OOOOa. The commenter states that the EPA previously considered these sources and determined that requiring controls was not appropriate. The commenter notes that the "average" whole gas emission rates emitted by continuous low bleed pneumatic devices and non-affected storage vessels are allowed up to 0.11 kilogram (kg)/hour (hr)/device and up to 0.675 kg/hour/tank, respectively. By comparison, the commenter states that emission leak rates from the 1995 Leak Protocol are 0.0045 kg/hour/gas valve (average factor from Table 2-4) and 0.098 kg/hour/gas

[162] https://www.epa.gov/sites/production/files/2016-08/documents/2016-compliance-guide-oil-natural-gas-emissions.pdf

support EPA's Proposal to reduce monitoring frequency at these sources. The commenter asserts that, in any event, the data from the study are from a very limited set of low production wells, representing a tiny fraction of wells that exist around the country and are subject to the NSPS, thus EPA cannot lawfully justify weakening the BSER, nor can it determine that its revised standards reflect the BSER, based only upon this study.

Response: The EPA disagrees with the commenters' criticisms of EPA's analysis of the FW Study in this rulemaking. Contrary to the commenters' claim, the EPA did not draw different conclusions in 2016 and 2018 regarding low production well sites based on the FW Study. In fact, the EPA did not draw *any* conclusion specific to low production well sites based on the FW Study in 2016, must less a conclusion different from that in 2018. As shown in the TSD for the 2016 NSPS OOOOa rulemaking,[232] the EPA reviewed the FW Study (1) as part of its review of a broader study (the ICF study)[233] that was used in support of the estimates of control efficiencies for OGI monitoring at various frequencies, (2) as a source of information for the estimate of 22 well sites per company when estimating the costs of the monitoring program, and (3) as support for the 1.18 percent leak fraction discussed in that rule. It was not until the present rulemaking that the EPA drew any conclusion regarding low production well sites based on the FW Study. Specifically, in reconsidering the application of the fugitive emissions standards in the 2016 NSPS OOOOa to low production well sites, the EPA reviewed new information received since the 2016 NSPS OOOOa rulemaking and re-examined previously available information, including the FW Study. This time, however, the EPA conducted a more in-depth and robust assessment of the FW Study, including portions that were not previously analyzed. Based on this assessment, the EPA discerned a distinction between non-low and low production well sites with respect to the types and amount of equipment used, which are key to estimating the amount of fugitive emissions. Based on thorough reexamination of the information within the FW Study and the review of new information received since the promulgation of the 2016 NSPS OOOOa, the EPA developed a separate model plant for low production well sites instead of relying on one well site model plant to analyze fugitive emissions for all well sites, irrespective of production levels, as the EPA did during the prior rulemaking.

The EPA's analysis of the FW Study is well documented in the FW Study memorandum supporting the 2018 proposal.[234] As discussed in that memorandum, the EPA identified well sites in the study that were producing at or below 15 boe per day, the same threshold considered for defining low production well sites in the 2016 NSPS OOOOa rulemaking.[235] The memorandum explains that EPA evaluated the average counts for each reported equipment type and the average methane emissions measured. Analyses of this information found that there was a statistical difference between the emissions of non-low and low production well sites, which further supported the need to examine the fugitive monitoring programs separately for low production well sites. Accordingly, the EPA developed a separate model plant analysis specific to low production well sites; based on that analysis and other considerations discussed in the

[232] See section 2.3.3 of the TSD for additional information, located at Docket ID No. EPA-HQ-OAR-2017-0483.
[233] ICF International. *Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries*. ICF International (Prepared for the Environmental Defense Fund). March 2014.
[234] Memorandum. Analysis of Low Production Well Site Fugitive Emissions from the Fort Worth Air Quality Study. May 18, 2018. EPA-HQ-OAR-2017-0483-0037.
[235] 80 FR 56612.

2018 proposal, the EPA proposed amendments to the monitoring frequency for low production well sites. Based on comments and information received on the proposal, the EPA further revised its low production well site model plant analysis, which is described in detail in the TSD to this final rule. As explained in Section V.B.4 of the preamble to this final rule, based on the revised analysis, the EPA concludes that monitoring of low production well sites is not cost-effective at any frequency. For the reasons explained above, EPA's detailed and targeted analyses for low production well sites in this rulemaking, which is well documented in the final rule preamble and supporting materials, could not be more different than the analysis for all well sites conducted during the 2016 NSPS OOOOa rulemaking that evaluated only one model plant. The EPA therefore rejects the commenters' claim that the EPA justified different conclusions based on the same study.

The EPA also disagrees with the commenters' contention that the FW Study does not support amending the monitoring frequency requirement for low production well sites. First of all, the FW study makes *no* conclusions or pronouncements specific to low production well sites, much less a conclusion that low production well sites "have high absolute emissions" and are "a significant source of emissions," as the commenter incorrectly claims.[236] Second, by characterizing the low production well site emissions as a percentage of non-low production well site emissions, the commenters presume that monitoring frequency should be directly proportional to the amount of baseline emissions. The commenters' presumption is incorrect because it fails to take into account monitoring and other associated costs, which the CAA requires that the EPA consider in determining the appropriate standard. See CAA section 111(a)(1). With regards to the commenters' criticism that the FW Study contains information for only a limited set of low production well sites, based on EPA's evaluation of all information received,[237] the EPA concludes that the information in the FW Study is the best available information on low production well sites and, as explained above, allows the EPA to conduct a more detailed and targeted analysis that is more representative of low production well sites than the analysis the EPA relied upon in the prior rulemaking.

For the reasons stated above, the EPA reasonably relies on the FW Study in its analysis and the resulting amendments to the monitoring frequency at low production well sites in the final rule.

Comment: Commenter (0785) argues that California's successful implementation of its very similar Oil and Gas Regulation also undermines EPA's justification for amending the current required monitoring frequencies for non-low and low production wells.[238] The commenter notes that California's Oil and Gas Regulation requires quarterly LDAR inspections of all wells, regardless of production.[239] Additionally, the commenter states that the LDAR costs are correlated with the number of components,[240] so sites with a relatively smaller number of components would have a similarly low cost to implement. Accordingly, the commenter believes

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[236] See Docket ID No. EPA-HQ-OAR-2017-0483-2041.
[237] See Memorandum. Summary of Data Received on the October 15, 2018 Proposed Amendments to 40 CFR Part 60, Subpart OOOOa Related to Model Plant Fugitive Emissions. February 10, 2020.
[238] Cal. Code Regs., tit. 17, § 95669.
[239] Ibid.
[240] CARB Staff Report: Initial Statement of Reasons, Appendix B: Economic Analysis, May 2016, pp. 35-36, available at https://www.arb.ca.gov/regact/2016/oilandgas2016/oilgasappb.pdf.

- The FW Study remains the best available source of information for defining the low production well site model plant.

Comment: Commenter (2194-L) believes that commenter (1009) fundamentally mischaracterizes scientific research and analysis conducted by scientists at EDF and other institutions on methane emissions in the oil and gas sector.[255] According to the commenter, these studies and other recent analysis show low production wells have significant levels of fugitive emissions, with absolute emissions that are comparable to non-low production sites (and higher than EPA's projected model facility emissions) and production-normalized loss rates that are far greater.[256] Much of the information provided in this submittal is a restatement of the original comment (2041).

Commenter (2232-L) provides input on commenter's (2194-L) supplemental filing submitted on February 21, 2019, that asserted a number of criticisms of industry comments, many of which attack statements or information submitted by the commenter (1009). Commenter (2232-L) expresses that at the center of commenter's (2194-L) supplemental filing comments are a series of studies and reports that present its perspectives on methane emissions related to the production of American natural gas and oil. Commenter (2232-L) states that each of these items present "highly inaccurate and questionable assessments and present them with strident evangelical certainty that vastly overstates their accuracy and value." To place the arguments and criticisms in context, commenter (2232-L) reviews each document cited by commenter (2194-L). Much of the information submitted was a repeat from the original comments in their original comment letter (1009).

Response: The supplemental comments summarized above, which are the commenters' rebuttals to one another, provide few points that were not already previously conveyed/submitted to the EPA and addressed elsewhere in this Chapter in EPA's response to the commenters' previous comments.

8.1.2.7 EPA Underestimates Emissions from Low Production Well Sites

Comment: Commenters (0729, 0785) indicate that the EPA underestimated the emissions from low production well sites, and thus failed to justify its proposal to adopt new less stringent monitoring requirements for low production well sites. Commenter (0729) states that the EPA bases its analysis of the new requirements on a 2011 study, reporting emissions data from just 27 low production wells, all located in Texas' Barnett Shale. According to the commenter, reliance on such geographically limited data is inappropriate since, as EPA has itself noted, "different basins have different leak rates." Moreover, the commenter contends that recent research suggests that the 2011 study underestimates leak rates, both in the Barnett Shale and other areas. The commenter notes that research has found emissions from low production wells to be highly skewed, with a small number of "super-emitters" accounting for a large proportion of emissions.[257] The commenter states that these super-emitters tend to be underrepresented in

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[255] See EPA-HQ-OAR-2017-0483-1006 at 15-26.
[256] See EPA-HQ-OAR-2017-0483-2041 at 101-104.
[257] Daniel Zavala-Araiza et al., Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites, 49 ENVTL. SCI. & TECH. 8167, 8168 (2015) (finding that "lower production sites (10-100

Chapter 14. IMPACTS OF THIS FINAL RULE

14.1 Proposed Amendments Will Increase Emissions that Contribute to Adverse Air Quality, Climate Change and Public Health Impacts

Comment: Commenters (0103, 0123, 0280, 0572, 0727, 0743, 0748, 0758, 0763, 0782, 0789, 0792, 0803, 0826, 1015, 1140, 1255, 1337, 1682, 2234) express concern that adopting the proposal as is would increase emissions of methane, volatile organic compounds (VOC), fine particulate matter (PM2.5), and hazardous air pollutants (HAP). Several commenters (0280, 0739, 0748, 0759, 0763, 0782, 0979, 1010, 1015, 1076, 1140, 1234, 1295, 1524, 1682, 2041) express support for the original 2016 New Source Performance Standards (NSPS) OOOOa and request that the EPA withdraw the proposed rule. Specific comments include:

- Commenter (1015) notes that according to the EPA, the leak detection and repair requirements of the 2016 standard are responsible for over half of the methane emission reductions, 90 percent of the HAP reductions, and a substantial reduction in emissions of VOC. The commenter believes that by suspending these requirements, as outlined in the proposal, the EPA would allow thousands of wells and compressor stations to continue leaking large volumes of air pollutants. Commenter (1255) believes that decreasing fugitive emissions monitoring frequency at compressor stations will increase total emissions of greenhouse gas (GHG) emissions and other air pollutants.
- Commenters (0103, 0572, 0763, 0789, 0792) note that the EPA estimates the proposal will increase air pollution by 380,000 tons of methane, 100,000 tons of VOC, and 3,800 tons of HAP over a six-year period (from 2019 through 2025).
- Commenters (0758, 0727, 1015) express concern that the proposal would replace existing standards with less stringent monitoring, repair, and certification requirements for oil and natural gas operators. The commenters believe the result of these actions would be a significant negative impact on air pollution, including an additional 480,000 tons of methane, 120,000 tons of VOC, and 4,700 tons of HAP through 2025.
- Commenters (0123, 0572, 0743, 1140, 1234, 1337) are concerned that reducing monitoring and other proposed provisions will increase the number of undetected leaks and increase methane emissions.
- Commenters (0803, 1015, 1337, 1682) contend that the proposal would significantly weaken what they believe are the reasonable standards within the 2016 rule and would allow hundreds of thousands of tons of additional HAP, methane, and VOC into the ambient air while wasting tens of millions of dollars of natural gas.
- Commenters (0572, 0743) assert that the EPA should be concerned only with emission reductions, not approving rules that result in increased emissions.

Commenters (0103, 0123, 0280, 0680, 0731, 0739, 0743, 0748, 0756, 0759, 0763, 0770, 0789, 0792, 0812, 0832, 1015, 1140, 1234, 1255, 1337, 2234) express concern regarding the adverse impacts that would be incurred from the increased air pollution from the proposal. The commenters assert that increased emissions of methane, VOC and HAP will have significant climate/environmental and harmful health impacts. Specific concerns expressed by commenters include:

- Commenter (0748) notes that increases in air pollution as the result of the proposed amendments could result in negative health impacts and some of the pollutants are precursors to the formation of ozone. The commenter contends that revising the 2016 rule goes directly against the EPA's mission to protect human health and the environment.
- Commenter (0280) states that oil and gas development also emits VOC, which contribute to ozone, smog, and toxic air pollution, and commenter (0123) expresses concern that increases in methane emissions will contribute to the loss of stratospheric ozone and the increase in tropospheric ozone.
- Commenters (0731, 0759, 0792, 0832, 1015, 1140, 1234, 1337) express specific concerns regarding the negative public health consequences that would result due to increases in methane, VOC and HAP emissions.
- Commenter (1015) states that communities have been negatively impacted by air pollution from oil and gas development, including exacerbated cases of asthma, sinus irritation and infection, nosebleeds, fatigue, peripheral neuropathy, benign tumors, and cancers.
- Commenter (0739) is concerned that the proposed rule will negatively impact the health of our children and communities, which will have to bear increasing costs of climate change impacts. Commenter (0759) is concerned about the impacts the increase in methane, VOC and HAP (*e.g.,* benzene) emissions will have on Latino communities across the country, especially the children and the elderly. The commenter states that 1.81 million Latinos live within a half mile of existing oil and gas facilities and cites a report by the National Hispanic Medical Association and the League of United Latin American Citizens entitled "Latino Communities At Risk: The Impact of Air Pollution from the Oil and Gas Industry" which found, "…that many Latino communities face an elevated risk of cancer due to toxic air emissions from oil and gas development."
- Commenter (0792) states that VOC react with nitrogen oxides to form ground-level ozone, which can be especially harmful for children who are active outdoor, affects sensitive vegetation and ecosystems, and impacts trees, plants, forests, parks, wildlife refuges, and wilderness areas. Commenter (0782) notes that, since VOC contribute to ground-level ozone and cause multiple health impacts, including shortness of breath, airway inflammation, and aggravation of asthma, lung disease and chronic obstructive pulmonary disease, and HAP are known or suspected to cause cancer, the commenters believe adopting the proposal would impact workers and their families. The commenter cites the following EPA statements within the proposal, "'…the EPA believes that the environmental health or safety risk addressed by this action may have a disproportionate effect on children…' [and] EPA admits that weakening commonsense methane standards will 'degrade air quality and adversely affect health and welfare.'" The commenter believes the EPA should retain the 2016 standard to ensure that communities, workers, and their families near oil and natural gas development remain protected from harmful air pollution.
- Commenters (0731, 0812) believe that increased VOC emissions will degrade air quality and adversely affect health and welfare effects. The commenters allege that air pollution from the oil and gas industry harms human health and increasing this pollution increases the harm.
- Commenter (1337) is concerned about the impacts of increased emissions of hazardous air pollutants, especially benzene. The commenter notes that there are increased

incidences of asthma and blood pressure and cardiovascular diseases from living near oil and gas wells, based on an article published in *Environmental Research* in 2018.[447] The commenter believes that this trend warrants further research and should not be ignored by the EPA, whose mandate is to protect the public health and welfare.

- Commenter (0271) believes that adoption of the proposal will make it harder to restore Utah's healthy air. Since the Uinta Basin of eastern Utah is a major center of oil and gas production and designated as an ozone nonattainment area, the commenter is concerned that any increase in volatile organic compound emissions from the proposal will make it harder to address these serious air pollution problems. The commenter cites a 2013 industry study that demonstrated that oil and gas development is responsible for 97 percent of the volatile organic compounds generated in the Uinta Basin.
- Commenter (0748) has completed an 18-month air quality study to research the impacts of oil and gas development on air quality in Boulder County, Colorado. The commenter notes that there is a strong correlation between measured air quality and oil and gas development, as northeasterly winds reliably bring higher levels of methane, ethane, and propane from oil and gas development in Weld and Larimer counties. Since Boulder County, Colorado is a nonattainment area for the 2015 ozone National Ambient Air Quality Standards (NAAQS), commenters (0680, 0748) note that increased emissions from oil and gas production will contribute to additional negative impacts on air quality in Colorado Front Range communities and parts of Rocky Mountain National Park.
- Commenter (0768) believes that the EPA action is necessary to prevent upwind states from emitting pollution that detrimentally impacts the health of New York citizens. The commenter states that while, as a state, New York enjoys a strong track record of protecting public health and welfare from air pollution, they continue to monitor nonattainment with the NAAQS for ozone. According to the commenter, this is largely due to pollution transport from upwind areas. The commenter adds that they will continue to limit emissions from new and existing oil and gas equipment through the implementation of their Methane Reduction Plan.
- Commenters (2234) assert that the EPA's proposal to weaken methane leak inspection and repair requirements for oil and gas operations and (Bureau of Land Management) BLM's rule gutting measures designed to reduce methane venting, flaring and leaks from oil and gas operations on public lands will inflict tremendous harm on American citizens and on the air and water which we all rely. The commenters provide that weakening federal methane regulations will have real-world consequences on families and individuals who live near oil and gas operations. The commenters note that increased emissions of methane, VOC and HAP (citing potential increase in emissions from the oil and natural gas Reconsideration rule and emissions increases due to the BLM rule) can exacerbate asthma and respiratory illnesses and have been linked to cancer, birth defects, and nervous system damage.[448]

[447] Lisa M. McKenzie, James Crooks, Jennifer L. Peel, Benjamin D. Blair, Stephen Brindley, William B. Allshouse, Stephanie Malin, John L. Adgate. "Relationships between indicators of cardiovascular disease and intensity of oil and natural gas activity in Northeastern Colorado" Environmental Research, Volume 170, March 2019, Pages 56-64.
[448] "Fossil Fumes: a public health analysis of toxic air pollution from the oil and gas industry." Clean Air Task Force. June 16, http://www.catf.us/resources/publications/files/FossilFumes.pdf.

- Commenters (0123, 0280, 0680, 0727, 0733, 0741, 0743, 0756, 0770, 0792, 1015, 2234) are concerned that the increase in GHG emissions will present additional losses/adverse impacts and hazards via climate change in the U.S.
  - Commenter (0280) expresses concern that the proposal would hinder the ability to avoid the worst impacts of climate change, as the oil and gas industry is the largest domestic source of methane. The commenter notes that methane is the primary component of natural gas and is a powerful GHG contributing to climate change.
  - Commenter (0123) states that, since methane is a more potent GHG that can absorb 86 times more energy per unit of mass than carbon dioxide (CO_2), the commenter believes that the EPA should be requiring readily available control technologies to continue controlling methane emission from oil and gas development.
  - Commenter (0770) believes these will include, "more frequent and intense extreme weather and climate-related events" that will threaten infrastructure and ecosystems across the nation," and economic losses in agriculture and tourism.
  - Commenter (1015) states that the public is currently experiencing the effects of climate change, including increasingly frequent and dangerous wildfires, weather events, and drought. Commenter (0743) is concerned that the increase in methane emissions will impact our climate and cause increasingly strong fires, drought, intense and frequent hurricanes, coastal and island flooding, and melting ice caps. The commenter notes that these impacts present risks to farmers and ranchers, whose livelihoods are dependent on the land and weather.
  - Commenter (0792) expresses concern with impact to wildlife from climate change and air pollution. The commenter believes that weakening the 2016 standards will allow for more GHG emissions, which will make natural gas a less cleaner energy source, due to the potent emissions of methane. The commenter notes that hunters and anglers are already seeing the impacts of a changing climate negatively impacting wildlife, as record-shattering temperatures, extreme weather events, more intense drought and floods, and longer fire seasons pose unprecedented perils to wildlife.
  - Commenters (0680, 0756) point out specific evidence of increasing impacts as a result of climate change. Commenter (0680) notes that climate change impacts have caused Glacier, Joshua Tree, and Saguaro National Parks to lose their namesake features. The commenter also notes that sea level rise is rapidly eroding coastlines and threatening Everglades and Biscayne National Parks and Cape Hatteras. The commenter states that Shenandoah National Park is experiencing warmer water temperatures that are threatening native species like brook trout. The commenter also states Rocky Mountain and Great Smoky Mountain National Parks are experiencing record wildfires, both in intensity and scope. Commenter (0756) states that the 2018 United Nations Climate Change Conference in Katowice, Poland provided further evidence of human made climate change.
  - Commenters (0733, 0741) believe that the "Fourth National Climate Assessment" and the UN article, alone, provide enough legal evidence to compel the conclusion that the proposed regulation should be rejected.

- Commenter (0727) provides some background information about Intergovernmental Panel on Climate Change (IPCC) including its purpose, when it was established and by whom, and a description of its members. Commenter (0727) also quotes Dr. Tony Pereira, a Fulbright Scholar, Climate Reality Leader and University of California, Los Angeles, ME PhD, who is also working as a Professor of Engineering, Applied Science and Eco-Sustainability, who frequently stresses the review process for reports supporting climate change and the lack of support (*e.g.,* reports or analysis) from climate change deniers. The commenter notes that Dr. Pereira gives presentations, lectures and workshops on eco-sustainability all over the country and worldwide for well over two decades, including identifying the causes and the effects of global warming and possible solutions on how to transition to an eco-sustainable society with clean, renewable energy, organic food and water independence, halt global warming, capture carbon and sink CO_2.
- Commenters (2234) assert that, although the Administration may view climate change as a hoax, destructive and costly extreme wildfires, extended heatwaves, and supercharged storms have become a new reality and methane emissions from oil and gas operations are a major contributor to the climate change crises. The commenter emphasizes that methane emissions control results in gas savings and a benefit (providing statistics).

Response: While the public may experience forgone benefits as a result of this action, the potential forgone emission reductions (and related benefits) from the final amendments are small compared to the overall emission reductions (and related benefits) from the 2016 NSPS OOOOa. Based on the revisions in the final rule, we estimate a decrease in the emission reductions anticipated by the 2016 NSPS OOOOa of about 12-15 percent for methane and about 7-9 percent for VOC in the year 2025.

These estimates are based on the information estimated in the 2016 OOOOa Regulatory Impact Analysis (RIA), with specific updates to the estimates for the fugitive emissions requirements. For the final rule, the EPA has updated the key factors which influence the costs and emissions reduction estimates for the fugitive emissions requirements.[449] These updates affect the estimated emissions reductions achieved by the fugitive emissions requirements in the 2016 NSPS OOOOa, as well as the estimated emissions reductions achieved as a result of revisions to those requirements in this final rule. The only update to the estimated emissions reductions for other sources regulated in the 2016 NSPS OOOOa is to change the first year in which sources are considered affected from 2016 to 2015 to maintain consistency with the 2020 RIA; this update also applies to fugitive emissions sources.

Table 14-1 presents the unrounded emissions reductions based on projections for the 2016 OOOOa RIA.[450] Additionally, Table 14-1 presents a second row for the fugitive emissions

[449] See Section 3.1 of the 2020 final rule RIA.
[450] Document can be found at https://www3.epa.gov/ttn/ecas/docs/ria/oilgas_ria_nsps_final_2016-05.pdf. The projections for the 2016 OOOOa RIA are based on the same methodology used to create Table 3-4 in that document, however, the numbers differ slightly as new projected sources from 2015 are now considered affected, consistent with the 2018 proposal and this final rule.

requirements of the 2016 NSPS OOOOa based on the updated emissions reductions. The updated estimates show fewer fugitive emissions reductions projected in 2025 than estimated when the 2016 NSPS OOOOa was promulgated.

Table 14-1 Emissions Reductions Under the 2016 NSPS OOOOa from the 2016 RIA and under the Updated Baseline for the Final Reconsideration, 2025

		2025 Reductions (short tons)	
Source/Emissions Point	**Document**	**Methane**	**VOC**
Fugitive Emissions	*2016 OOOOa RIA*	*370,207*	*102,908*
	2020 Reconsideration RIA	*170,318*	*47,344*
Oil Well Completions and Recompletions	2016 OOOOa RIA	123,450	103,377
Pneumatic Pumps	2016 OOOOa RIA	28,533	7,932
Total	***2016 OOOOa RIA***	***522,190***	***214,217***
	2016 OOOOa RIA Adjusted for Updated Projection of Fugitive Emissions	***322,301***	***158,653***

Table 14-2 compares the updated emissions reductions estimated for the 2016 NSPS OOOOa compared to the emissions reductions change that is projected based on the final amendments of this action. For example, 32,473 short tons of methane emissions in 2020 that were projected to be reduced by the requirements of the 2016 NSPS OOOOa are projected to not be reduced as a result of the standards in this final rule. Overall, there is a 10 percent decrease in methane emissions reductions projected for 2025, as shown in Table 14-2. For VOC emissions, there is a 6 percent decrease in emissions reductions projected for 2025.

Table 14-2 Percent Decrease in Emissions Reductions Under Final Reconsideration

	2025 Reductions (short tons)	
Source Document	**Methane**	**VOC**
Under Final Reconsideration	*-40,231*	*-11,183*
2016 OOOOa RIA Adjusted for Updated Projection of Fugitive Emissions	*322,301*	*158,653*
Percent Decrease in Emissions Reductions Under Final Reconsideration	***12%***	***7%***

While the above analysis does not account for any changes to the projected populations of other sources covered by the 2016 NSPS OOOOa (*i.e.,* oil well completions and recompletions and pneumatic pumps), we performed a sensitivity analysis by rescaling the emissions reductions for these regulated sources by the scale of projected wells drilled according to Annual Energy Outlook. In the 2016 NSPS OOOOa, we used the 2015 Annual Energy Outlook (AEO2015). For this final rule, we use the AEO2020.

Table 14-3 Projections of Oil and Gas Natural Gas Total Lower 48 Wells Drilled in 2025, AEO2015 and AEO2020

	AEO2015 Reference Case (1000s wells)	AEO2020 Reference Case (1000s wells)	Ratio of AEO2020 to AEO2015
2025	47.4	31.7	0.67

The ratios presented in Table 14-3 were then applied to the projected emissions reductions for non-fugitive emissions sources presented in Table 14-1, as shown in Table 14-4.

Table 14-4 Percent Decrease in Emissions Reductions Under Final Reconsideration with Non-Fugitive Emissions Reductions Rescaled by Ratio of AEO2020 to AEO2015 Well Drilling Projections, 2025

	2025 Reductions (short tons)	
Source Document	**Methane**	**VOC**
Under Final Reconsideration	*-40,231*	*-11,183*
2016 OOOOa RIA Adjusted for Updated Projection of Fugitive Emissions and Rescaling of Non-fugitive Emissions Reductions	*272,000*	*121,814*
Percent Decrease in Emissions Reductions Under Final Reconsideration	***15%***	***9%***

The result of this sensitivity analysis is a decrease of methane emissions reductions of 15 percent in 2025, and a decrease of VOC emissions reductions of 9 percent in 2025.

Furthermore, this action does not affect the level of public health and environmental protection already being provided by existing NAAQS and other mechanisms in the Clean Air Act (CAA). This action does not affect applicable local, state, or federal permitting or air quality management programs that will continue to address areas with degraded air quality and maintain the air quality in areas meeting current standards. Areas that need to reduce criteria air pollution to meet the NAAQS will still need to rely on control strategies to reduce emissions.
The EPA acknowledges that forgone environmental and human health benefits may be associated with forgone emission reductions. These impacts are discussed in the RIA and monetized to the extent possible. Since the objective of regulatory impact analysis is to capture overall welfare impacts of regulation, the RIA encompasses both cost reductions and forgone environmental and human health benefits.

Comment: Commenters (0803, 1015, 1337, 1682) express concern that mounting scientific evidence underscores the need for further reductions of methane emissions from the oil and gas sector. The commenters cite a 2018 study in the journal *Science* where researchers found that the EPA has underestimated methane emissions from the oil and gas industry by almost 60 percent.

Response: The *Science* paper (Alvarez, Zavala-Araiza et al. 2018) provides results from a number of the authors' analyses, including those incorporating both observational and component-level approaches. The analysis noted by the commenter (here labeled as "Analysis 1") includes the study authors' modeling of data collected from previous observational studies for the production and gathering segments (*i.e.,* emission measurements were made off-site, downwind of the facilities, and emissions cannot be attributed to specific equipment, components, or processes) and updated results of previous component-level studies for other segments. The authors then compare the national outputs resulting from Analysis 1 with other assessments, both 'top-down' (*e.g.,* ambient measurements using aircraft and satellite that infer aggregate emissions from all sources over large areas) and 'bottom-up,' and with previous national-level results calculated by the EPA as part of the U.S. GHG Inventory. Analysis 1 is the origin of the statistics cited by the commenters (*e.g.,* the 60% difference in national emission estimates between the study and the U.S. GHG Inventory). The results of Analysis 1 in the *Science* paper cannot be compared directly with the inputs to the OOOOa analysis because those inputs are specific to equipment covered by OOOOa.

The *Science* paper, in the Supporting Information (S.I.), does provide another analysis, (here labeled "Analysis 2") using component-based measurements and other methods to develop national emission estimates for a number of equipment types and practices across the oil and gas supply chain. For example, Analysis 2 provides an estimate of national emissions from equipment leaks (category most equivalent to production segment fugitives in OOOOa) in oil and gas production of 620 kT CH4 (570-670 kT CH4) for the year 2015. Using the national count of oil and gas wells in 2015 (1,018,053) gives an average emission rate from equipment leaks per well of 0.6 tonnes (0.6-0.7 tonnes) per year, which is within range of the values used in the EPA's NSPS OOOOa analysis, which vary from 0.2 to 3.0 tonnes of methane per well from equipment leaks depending on well type.

Alvarez et. al. (2018) found agreement between the national estimates developed in Analysis 1 and with other top-down studies and found that national estimates developed in Analysis 2 were lower than results of the top-down studies. Alvarez et al. (2018) believe that the large difference in emission estimates developed with top down approaches and those estimates presented in Analysis 2 is a result of conventional inventories systematically underestimating total emissions due to the omission of periodic spikes in emissions during abnormal operating conditions (*e.g.,* malfunctions). The *Science* paper supports the results of Analysis 1, with a top-down analysis. The EPA continues to work through its stakeholder process to review new data as they become available, including newly available data from the EPA's Greenhouse Gas Reporting Program (GHGRP) and research studies, to assess how these and other data sources may be used to further improve emissions estimates.

Regulatory Impact Analysis for the Review and Reconsideration of the Oil and Natural Gas Sector Emission Standards for New, Reconstructed, and Modified Sources

EPA-452/R-20-004
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Regulatory Impact Analysis for the Review and 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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Table 3-4 Total Reconsideration-impacted Source Counts for Finalized Option 3, 2021 to 2030

Year	Non-Low Production Wellsites	Low Production Wellsites	Gathering and Boosting Stations	Certifications	Total
2021	42,000	18,000	1,500	1,600	63,000
2022	48,000	23,000	1,700	1,600	74,000
2023	54,000	28,000	1,900	1,700	85,000
2024	59,000	33,000	2,100	1,700	97,000
2025	65,000	39,000	2,300	1,700	110,000
2026	70,000	46,000	2,500	1,700	120,000
2027	75,000	52,000	2,800	1,700	130,000
2028	80,000	59,000	3,000	1,700	140,000
2029	84,000	66,000	3,200	1,700	150,000
2030	88,000	73,000	3,400	1,700	170,000

Note: Total reconsideration-impacted sources include sources that are projected to change their activity as a result of the reconsideration 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 final action compared to the baseline. The table does not include estimated counts of NSPS-affected facilities whose controls are unaffected by the reconsideration. Estimates may not sum due to independent rounding.

Table 3-5 Reconsideration-impacted Well Site Counts by Alternative Fugitive Emissions Standards Status for Finalized Option 3, 2021 to 2030

Year	Non-Alternative Fugitive Emissions Standard State		Alternative Fugitive Emissions Standard State	
	Non-Low Production Wellsites	Low Production Wellsites	Non-Low Production Wellsites	Low Production Wellsites
2021	34,000	14,000	7,800	4,600
2022	39,000	17,000	8,900	5,600
2023	44,000	21,000	9,900	6,800
2024	48,000	25,000	11,000	8,000
2025	53,000	30,000	12,000	9,400
2026	57,000	35,000	13,000	11,000
2027	61,000	40,000	14,000	12,000
2028	65,000	45,000	15,000	14,000
2029	68,000	51,000	16,000	15,000
2030	72,000	57,000	16,000	17,000

Note: Projected sources under alternative fugitive emissions standard include all reconsideration-impacted well sites in California, Colorado, Pennsylvania, and Utah; 80 percent of well sites in Ohio; and 5.5 percent of well sites in Texas.

3.2.4 Forgone Emissions Reductions

Table 3-6 summarizes the estimated forgone emissions reductions associated with the finalized Option 3 compared to the baseline. Increases in emissions are estimated by multiplying the source-level increases in emissions from the updated baseline by the corresponding projected number of reconsideration-affected facilities. In the analysis, streamlined elements of the fugitive emissions monitoring requirements and closed vent system and technical infeasibility certification requirements are not associated with any direct emissions changes.[90] Therefore, all forgone emissions reductions are attributed to the frequency changes in the fugitive emissions monitoring program.[91] This does not include projected impacts on emissions from this final action resulting from reducing the monitoring frequency for affected compressor stations on the Alaska North Slope because, as noted, the EPA does not sufficient information on compressor stations there. Also, as noted in Section 3.2.1, some 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 measurable cost reductions or emission changes.

Table 3-6 Forgone Emissions Reductions under Finalized Option 3, 2021 to 2030

	Emission Changes			
	Methane (short tons)	**VOC (short tons)**	**HAP (short tons)**	**Methane (metric tons CO_2 Eq.)**
2021	19,000	5,200	200	430,000
2022	23,000	6,500	250	530,000
2023	28,000	7,900	300	650,000
2024	34,000	9,500	360	780,000
2025	40,000	11,000	420	910,000
2026	47,000	13,000	490	1,100,000
2027	53,000	15,000	560	1,200,000
2028	60,000	17,000	630	1,400,000
2029	68,000	19,000	710	1,500,000
2030	75,000	21,000	790	1,700,000
Total	450,000	120,000	4,700	10,000,000

Note: Estimates may not sum due to independent rounding.

[90] Streamlined elements of the fugitive emissions monitoring requirements include the removal of site map and observation path requirements in the monitoring plan and a reduction in the information required to be recorded and reported. After review of the specific requirements, for reasons explained in the Section V of the preamble to the final rule, several elements of the existing program were deemed redundant or not critical to demonstrating compliance with the rule. Emissions should not be affected by the change in certification requirements to the extent that 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 the information needed to estimate the potential for emissions impacts, if any, when moving from professional engineer certifications to in-house engineer certifications.

[91] Note that we estimate no change in emissions for well sites projected to be covered under equivalent state programs as discussed in Section 3.2.2.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2017–0483; FRL–9984–43–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. In 2017, the EPA granted reconsideration on the fugitive emissions requirements, well site pneumatic pump standards, and 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 December 17, 2018. 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 December 17, 2018.

Public Hearing. EPA is planning to hold at least one public hearing in response to this proposed action. Information about the hearing, including location, date, and time, along with instructions on how to register to speak at the hearing, will be published in a second **Federal Register** notice.

ADDRESSES:

Comments. Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2017–0483, at *https://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 the 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.

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

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 *Regulations.gov.* Although listed, 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 *https://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 *https://www.regulations.gov* or email. This type of information should be submitted by mail as discussed in the **SUPPLEMENTARY INFORMATION** 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 *https://www.regulations.gov* website allows you to submit your comments anonymously, 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 *https://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 digital storage media 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 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 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).

V. 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.

VI. Discussion of Provisions Subject to Reconsideration

As summarized above, the EPA is proposing to address a number of issues that have been raised by different stakeholders through several administrative petitions for reconsideration of the 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

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 categorically unavailable 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 design and construction of a new site and therefore new sites were categorically ineligible for the technical feasibility provision. 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 may require 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 may require 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.

The EPA solicits comment on whether the scenarios described above present circumstances where control of a pneumatic pump may be technically infeasible despite the site being newly designed and constructed, as well as other examples of technical infeasibility for a greenfield site. While the additional cost in the design and construction of a new site for selecting a control device that can control additional pneumatic pump emissions (*e.g.,* selecting a flare or slightly larger boiler that can accommodate such flows) in many cases will not be high, the scenarios raised in petitions for reconsideration suggest that there might be 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 categorical distinction between greenfield sites and non-greenfield sites (and the categorical restriction of the technical infeasibility provision to existing sites) for the pneumatic pump requirements. The proposal would avoid the potential of requiring a greenfield site to control 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 infeasibility scenarios at a new construction site. We also solicit comment on cost information related to the additional costs related to selecting 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 to provide: (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:

- Annual monitoring would be required at well sites with average combined oil and natural gas production for the wells at the site 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'');
- Biennial monitoring (once every other year) would be required for well sites with average combined oil and natural gas production for the wells at the site less than 15 boe per day averaged over the first 30 days of production (''low production well sites''); and
- Monitoring may be stopped once all major production and processing equipment is removed from a well site such that it contains only one or more wellheads.

Non-low Production Well Sites. The 2016 NSPS OOOOa requires initial and semiannual fugitive emissions monitoring using optical gas imaging (OGI) for the collection of fugitive emissions components located at well sites. In the 2016 NSPS OOOOa preamble, the EPA stated that ''both semiannual and annual monitoring remain cost-effective for reducing GHG (in the form of methane) and VOC emissions.'' 81 FR 35855. Several petitioners requested that the EPA reconsider the frequency of monitoring,[7] with one petitioner asserting that the EPA's cost-effectiveness analysis is not accurate and should be revised.[8] In response, the EPA has reviewed the data provided by the petitioner, as well as other data that have become available since promulgation of the 2016 NSPS OOOOa. Based on this review, we have updated our model plant analysis. Although under the updated analysis, semiannual monitoring may appear to be cost-effective, we have identified several areas of our analysis that indicate we may have overestimated the emission reductions and, therefore, the cost effectiveness, due to gaps in available data and factors that may bias the analysis towards overestimation of reductions. Therefore, the semiannual monitoring may not be as cost-effective as presented, and the EPA is proposing to revise the monitoring frequency to require annual fugitive emissions monitoring at non-low production well sites. Provided below is a detailed discussion of (1) how we revised the model plant analysis based on our review of the data; and (2) areas of our analysis that indicate we may have overestimated the emission reductions and in turn the cost effectiveness of the monitoring frequencies analyzed.

First, the EPA reviewed the available information and determined several updates were necessary to the non-low production well site model plants. As described in the TSD, the EPA evaluated the cost-effectiveness of the fugitive emissions monitoring program using model plants that represent average equipment and fugitive emissions component counts per well site.[9] We updated the model plants 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. The petitioner provided information that included counts for major production and processing equipment located at well sites.[10] For example, the data included the count of separators per well site and demonstrated that, on average, there are 3 separators per natural gas well site and oil well site. In comparison, the EPA model plants include 2 separators per natural gas well site and 1 separator per oil well site. While similar differences were observed for other types of major production and processing equipment, we maintained the estimates derived from the GHGI because the data included in the GHGI is the most up-to-date information available and the petitioner was not able to provide information on when the fugitive emissions monitoring occurred at the well sites presented in their data set.

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.[11] For purposes of the model plant, we are adding one controlled storage vessel with one PRD. We recognize that many well sites may have more controlled storage vessels, suggesting that we should add more than one controlled storage vessel to the model plant, while other well sites may not have any controlled storage vessels that are subject to fugitive emissions monitoring. The data provided by the petitioner[12] did not include the number of storage vessels at natural gas well sites, but included an estimated average of 7 storage vessels per oil well site. However, the data was not provided in a form sufficient to indicate whether these storage vessels are controlled or subject to fugitive emissions monitoring. Therefore, we did not incorporate any information from the petitioner related to storage vessel counts at well sites. 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

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

[8] See Docket ID No. EPA–HQ–OAR–2010–0505–7682.

[9] See TSD for additional information.

[10] 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.

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

[12] 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.

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 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.

Baseline emissions (uncontrolled) 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. The petitioner 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. However, in creating these new average emissions factors, the petitioner used correlation equations in the 1995 Protocol. These correlation equations were derived from leak studies using Method 21 of Appendix A–7 to Part 60 (''Method 21'') and are based on specific leak definitions when using Method 21. The correlation equations do not apply to monitoring using OGI, as it is not possible to correlate OGI detection capabilities with a Method 21 instrument reading provided in parts per million (ppm). Correlation equations for OGI do not currently exist and would be difficult to develop because OGI either sees fugitive emissions or it does not; there is no emissions scale as there is with Method 21. As such, at best, only average factors for visualized emissions and no visualized emissions would be possible (similar to the ''leak'' and ''no leak'' factors in the 1995 Protocol specific to Method 21). In order to develop such factors, an extensive dataset of OGI data and bagging studies, similar to the studies used to develop the factors presented in the 1995 Protocol would be needed. Therefore, the approach of scaling emissions factors as presented by the petitioner for the non-storage vessel PRD fugitive emissions components does not adequately address the differences in emissions correlations when using Method 21 and OGI, and therefore we have not evaluated the cost of control using the scaled factors presented by the petitioner. 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,* located at Docket ID No. EPA–HQ–OAR–2017–0483. Thus, 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. We are soliciting comment on the use of the average emissions factors and additional information or alternative methodologies that should be considered to refine our estimates of fugitive emissions.

While updating the model plants, the EPA identified three areas of the analysis that raise concerns regarding the emissions reductions: (1) The percent emission reduction achieved by OGI, (2) the occurrence rate of fugitive emissions at different monitoring frequencies, and (3) the initial percentage of fugitive emissions components identified with fugitive emissions. As described in detail below, the EPA acknowledges that emission reductions may have been overestimated, even in our updated model plants.

First, several stakeholders have raised concerns regarding the percent emission reductions (*i.e.,* control effectiveness) of OGI monitoring at the various monitoring frequencies. In the analysis described in the TSD, the EPA estimates emission reductions of 30 percent for biennial monitoring, 40 percent for annual monitoring, 45 percent for stepped monitoring, 60 percent for semiannual monitoring, and 80 percent for quarterly monitoring.[19] The estimates for annual, semiannual, and quarterly monitoring frequencies are the same as those during used for the 2016 NSPS OOOOa. Stakeholders have raised specific concerns regarding the control effectiveness values for semiannual and quarterly monitoring. One stakeholder asserts that the ''EPA's leak emission reduction estimates are based on a LDAR control efficiency model with high uncertainty and biased by flawed and unrepresentative data and assumptions.'' [20] Specific concerns

[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.*

[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.

[19] See TSD for additional information related to OGI control effectiveness.

[20] See ''Methane Emissions from Natural Gas Transmission and Storage Facilities: Review of

Continued

raised by this stakeholder include the comparison of OGI control effectiveness to Method 21 control effectiveness. The stakeholder noted that the EPA based the Method 21 control effectiveness evaluation on information from the Synthetic Organic Chemical Manufacturing Industry (SOCMI) which the stakeholder suggests overestimates fugitive emissions because this data is not representative of the oil and natural gas sector. We are soliciting comment and information that would support a revision of the evaluation of the Method 21 alternative that is more representative of the oil and natural gas industry.

This stakeholder also raised concerns that the estimated control efficiency of 80 percent for quarterly monitoring is too low, suggesting 90 percent would be more appropriate for quarterly monitoring and 80 percent for annual monitoring.[21] The stakeholder references a report by the Canadian Association of Petroleum Producers (CAPP) that estimated a net-weighted decrease of component-specific emissions factors following the implementation of best management practices, also published by CAPP.[22] [23] The EPA has reviewed this report from CAPP and the associated best management practices to determine if updates to our estimated control efficiencies for OGI are appropriate. In our analysis [24] of the information presented by CAPP, we are unable to conclude that annual monitoring with OGI will achieve 80 percent emission reductions because there is no information regarding the type of detection method used or repair requirement related to the facilities that provided data for the CAPP emissions factor update study. The related Best Management Practices document provides some information about the recommended frequency of monitoring; [25] however, the information provided for the CAPP study does not specify what monitoring frequencies were implemented at the facilities. Therefore, the TSD continues to use 80 percent as the best estimated control effectiveness for quarterly monitoring.[26] While the EPA's estimated emission reductions are based on the best currently available information, there are considerable uncertainties associated with that information and the consequent reductions, and 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. The EPA is requesting information on any analyses performed on the emission reductions achieved with OGI monitoring at different monitoring frequencies and the data underlying these analyses, including information on how the data was gathered, what the data represents, and how the analysis was performed.

Second, because the model plants assume that the percentage of components found with fugitive emissions is the same regardless of the monitoring frequency, we acknowledge that we may have overestimated the total number of fugitive emissions components identified during each of the more frequent monitoring cycles. The percentage of components found with fugitive emissions is similar to the occurrence rate (*i.e.,* the percentage of components not "leaking" that start to "leak" between monitoring cycles) of leak detection and repair (LDAR) programs. Appendix G of the 1995 Protocol describes how to calculate the occurrence rate.[27] When we have evaluated the use of Method 21 as an alternative for OGI in the fugitive emissions requirements of the 2016 NSPS OOOOa, we assumed occurrence rates that decrease with increasing monitoring frequencies, consistent with the 1995 Protocol. However, when evaluating the use of OGI, we assumed a constant percent of fugitive emissions components will be identified with fugitive emissions at each monitoring event, regardless of the number of monitoring events each year, which is counter to the 1995 Protocol and our evaluation of the Method 21 alternative. That is, the model plant analysis assumes that the same number of components will be identified with fugitive emissions during each monitoring event, regardless of how frequently monitoring occurs. Specifically, we currently assume that 4 components will have fugitive emissions during a single annual period if monitored annually, while 8 components will have fugitive emissions during a single annual period if monitored semiannually. While there is uncertainty regarding the number of components identified with fugitive emissions, as described below, the use of a single percentage for all monitoring frequencies may overestimate the number of fugitive emissions identified during more frequent monitoring events, such as semiannual monitoring. We are soliciting information to evaluate how the percentage of fugitive emissions identified changes with frequency to revise the model plant analysis.

Finally, in addition to the uncertainty described above regarding the percentage of fugitive emissions at the various monitoring frequencies, there is concern regarding the value that the EPA uses as an initial percentage in the model plant analysis. In the analysis for the 2016 NSPS OOOOa, we assumed a value of 1.18 percent based on information used in previous rulemakings for the SOCMI.[28] One petitioner provided data to demonstrate lower percentages of fugitive emissions than used in our analysis. One data set included information from well sites in Colorado and the Barnett Shale region of Texas.[29] 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. Subsequent to the submission of their petition, this petitioner also provided additional data on the initial

Available Data on Leak Emission Estimates and Mitigation Using Leak Detection and Repair," prepared for INGAA by Innovative Environmental Solutions, Inc., June 8, 2018, located at Docket ID No. EPA–HQ–OAR–2017–0473.

[21] See memorandum *EPA Analysis of Fugitive Emissions Data Provided by INGAA* located at Docket ID No. EPA–HQ–OAR–2017–0483. August 21, 2018.

[22] See "Update of Fugitive Equipment Leak Emission Factors", prepared for Canadian Association of Petroleum Producers by Clearstone Engineering, Ltd., February 2014, located at Docket ID No. EPA–HQ–OAR–2017–0483.

[23] Canadian Association of Petroleum Producers, "Best Management Practice. Management of Fugitive Emissions at Upstream Oil and Gas Facilities", January 2007.

[24] See memorandum *EPA Analysis of Fugitive Emissions Data Provided by INGAA* located at Docket ID No. EPA–HQ–OAR–2017–0483. August 21, 2018.

[25] Canadian Association of Petroleum Producers, "Best Management Practice. Management of Fugitive Emissions at Upstream Oil and Gas Facilities", January 2007.

[26] See TSD for more information related to OGI control effectiveness.

[27] U.S. Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates. Appendix G. November 1995 (EPA–453/R–95–017).

[28] 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 is 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).

[29] See Docket ID No. EPA–HQ–OAR–2010–0505–7682.

fugitive emissions percentages for well sites located in 14 states.[30] 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 within the entire dataset; therefore, the 0.4 percent does not represent the average percentage of fugitive emissions components found with fugitive emissions at individual well sites, which is the information needed to evaluate fugitive emissions requirements at an individual well site. The EPA, therefore, 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 model plant approach and the standards for fugitive emissions in the 2016 NSPS OOOOa. Based on the EPA's analysis of the petitioner's data, the data result in an average percentage of 0.54 percent or an average of 2 components per well site with fugitive emissions during the initial monitoring survey.[31] This contrasts with the EPA's estimate of 4 components per well site with fugitive emissions during the initial monitoring survey, 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. Based on this information, we are concerned that 1.18 percent is too high and not representative of the oil and gas sector. However, as discussed in the memorandum, the EPA has insufficient information, based on what was provided by the petitioner, to determine if the information is representative of fugitive emissions monitoring consistent with the requirements of the 2016 NSPS OOOOa. Therefore, we have not incorporated a change in the percentage value used in the model plant analysis and are soliciting more information as described later in this subsection.

In summary, although the EPA has incorporated several updates into the model plant analysis, the three areas described above cause concern that our analysis may still overestimate emission reductions. Based on the model plant analysis, we estimated the cost of control for each of the monitoring frequencies to determine how the changes to the model plants would affect the determination of cost-effectiveness presented in the 2016 NSPS OOOOa, noting that the revised analysis, notwithstanding its incorporation of additional information, does not address the three areas of concern described above. We applied the two approaches used in the 2016 NSPS OOOOa (single and multipollutant approaches)[32] for evaluating cost-effectiveness of the semiannual and annual monitoring frequencies for the fugitive emissions program for reducing both methane and VOC emissions from non-low production well sites.[33] For purposes of this reconsideration, we examined the emission reductions and costs for the fugitive emissions monitoring requirements at non-low production well sites at semiannual, annual, and stepped (semiannual for 2 years followed by annual monitoring thereafter) monitoring frequencies. This stepped monitoring frequency was based on a suggestion from one petitioner 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"[34] components.[35] While we have not established what would constitute an insignificant number of leaking components and the period of time before that number is reached, we have historically recognized that initial percentages of leaks are generally higher than subsequent leak percentages for the non-storage vessel PRD fugitive emissions components.[36] As a fugitive emissions program is implemented, leak percentages decline until they reach a "steady state." As illustrated in Figure 5–35 of the 1995 Protocol,[37] 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. We therefore evaluated a stepped approach, using 2 years as the initial period (as suggested by the petitioner) before reaching the steady state. Additional information regarding the cost of control and emission reductions is available in section 2.5 of the TSD located at Docket ID No. EPA–HQ–OAR–2017–0483.

These costs of control for both the semiannual and annual monitoring frequencies may appear to be reasonable for non-low production well sites. However, as explained above regarding the three areas of concern, we acknowledge that our updated analysis may overestimate the emission reductions achieved under semiannual monitoring and the number of fugitive emissions components identified during semiannual monitoring. Therefore, we are unable to conclude that semiannual monitoring is cost effective. While we have also overestimated the cost effectiveness of the stepped approach and annual monitoring for the same reasons discussed above, the overestimate would be less compared to that for semiannual monitoring. As mentioned earlier, petitioners have requested that we consider annual monitoring, which suggests that they are able to bear such costs. In light of all these considerations, we are therefore proposing to revise the monitoring frequency for the collection of fugitive emissions components located at non-low production well sites from

[30] Alaska, Arkansas, Colorado, Louisiana, Montana, New Mexico, North Dakota, Ohio, Oklahoma, Pennsylvania, Texas, Utah, West Virginia, and Wyoming.

[31] 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.

[32] 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 is 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.

[33] The TSD also include an analysis of the cost of control for the stepped monitoring frequency; however, we are not considering this for proposal in this action because we do not currently have information to understand how fugitive emission percentage change over time or how long it takes to achieve the steady state percentage at non-low production well sites.

[34] While the petitioner used the term leaking, 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.

[35] See Docket ID No. EPA–HQ–OAR–2010–0505–7682.

[36] 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.

[37] 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).

semiannual monitoring to annual monitoring.

We are soliciting comment on the proposed annual monitoring for non-low production well sites and additional information to address the uncertainties described previously. There are several well sites that have incorporated fugitive monitoring programs prior to the 2016 NSPS OOOOa for various purposes, including compliance with state or local requirements. Data from these programs could provide the information necessary to refine our model plant analysis. 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 or based on monitoring frequency; 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 on the stepped monitoring frequency for non-low production well sites, including information to determine the appropriate period for more frequent monitoring prior to stepping down to less frequent monitoring. We further solicit comment whether, should we still lack information of the type solicited in this paragraph, the existing uncertainties and absences of information described in this notice support the monitoring frequencies proposed in this notice, the monitoring frequencies in the 2016 NSPS OOOOa, or some other result.

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.

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.[38] Additional discussion about this model plant and the cost of control is included in the TSD. In light of the above, because fugitive emissions are anticipated to be extremely low and control costs are estimated to be elevated, we are proposing that monitoring may discontinue when all major production and processing equipment at a well site has been 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 VI.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

[38] 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 would also not be cost-effective because there are higher costs compared to annual monitoring.

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 final 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.[39] 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.[40] 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.'[41]

As we explain in detail in section VI.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. However, as described below, there is support for the petitioners' assertion that equipment counts can vary based on the amount of production at a well site.[42]

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 inverse 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.[43] 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.[44] 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.[45] 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."[46] We solicit information confirming or refuting this concern including analyses of 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 be of limited or no utility in this analysis.

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").[47] The EPA evaluated

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

[40] See Docket ID No. EPA–HQ–OAR–2010–0505–7685.

[41] See Docket ID No. EPA–HQ–OAR–2010–0505–7685, p. 5.

[42] See Docket ID No. EPA–HQ–OAR–2010–0505–7682.

[43] See Docket ID No. EPA–HQ–OAR–2010–0505–7682, p. 12.

[44] *Id.*

[45] See Docket ID No. EPA–HQ–OAR–2010–0505–12454.

[46] See Docket ID No. EPA–HQ–OAR–2010–0505–7685.

[47] "The Natural Gas Air Quality Study (Final Report)," prepared by Eastern Research Group, Inc.
Continued

the emissions calculation workbook included in Appendix 3–B of the Fort Worth 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.[48]

Given this information, the EPA for this proposal has 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 has 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 well site (defined as GOR ≥300). A discussion of the non-low production well site model plants is included in the discussion above 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 components, and therefore fewer fugitive emissions. 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 (contrary to our assumption in the 2016 NSPS OOOOa), a few outliers were identified suggesting that low production well sites may 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.

In addition to the potential overestimates of emissions discussed related to non-low production well sites, our re-assessment of our 2016 analysis indicates that we may have overestimated emissions and the potential for emission reductions from low production well sites. 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[49] 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 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

July 13, 2011, *available at http://fortworthtexas.gov/gaswells/air-quality-study/final/.*

[48] 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.

[49] 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, and solicit information regarding operations in other areas.

production well sites). Therefore, there is evidence to suggest that we may 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.[50] However, in section VI.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.

Despite the potential overestimation of emissions and emission reductions for low production well sites, we examined the costs and emission reductions for several monitoring frequencies to determine the cost of control for the newly created low production well site model plant. As a result of this review, there is evidence to support the petitioners' assertion that low production well sites are different than non-low production well sites. The TSD presents the cost of control for semiannual, stepped, annual and biennial monitoring frequencies.[51]

After considering the differences in emissions between non-low production and low production well sites, and the reasons to believe that we have overestimated emission reductions and percentage of fugitive emissions, we are proposing to change the current monitoring frequency for low production well sites from semiannual monitoring to biennial monitoring, or monitoring every other year. We are soliciting comment on the biennial 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 provide the combined production of oil and natural gas for the well site. In addition to soliciting comment on the biennial monitoring frequency, we are also soliciting comment and supporting data on 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. As noted in section VI.B.1 of this preamble, we received petitions requesting less frequent monitoring, specifically semiannual monitoring for compressor stations.[52] In this action, we are co-proposing semiannual and annual monitoring of the collection of fugitive emissions components located at compressor stations not located on the Alaskan North Slope. (See ''Well Sites and Compressor Stations Located on the Alaskan North Slope'' for the proposed actions related to those sites.)

Similar to the information received about fugitive monitoring at well sites, the EPA received information from two stakeholders regarding fugitive emissions monitoring at compressor stations.[53] [54] Some of the information provided the number of fugitive emission components monitored and the number and percentages of fugitive emissions components identified with fugitive emissions for 110 gathering and boosting compressor stations.[55] One of these stakeholders 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. One company provided the number of fugitive emissions identified during initial monitoring at 17 stations, and subsequent fugitive emissions counts for up to 6 total surveys, however, not all stations are represented in subsequent surveys. While fugitive emissions counts were included in this submission, no other information was provided about the number of components monitored. It was difficult for us to make any conclusions from the information, but we were able to recognize that for at least one company, the average 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. However, no conclusions can be drawn from this single data point and we did not make updates to the model plants as a result of this information. 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 included this analysis in the TSD. This analysis did not alter the conclusions that we had reached using the 1.18 percent value.

We are soliciting comment on our analysis of the information provided by this stakeholder,[56] including additional data that will allow for further analysis of fugitive emissions monitoring at

[50] See Docket ID Nos. EPA–HQ–OAR–2010–0505–7682 and EPA–HQ–OAR–2010–0505–7685.

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

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

[53] 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.

[54] 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.

[55] 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.

[56] 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.

compressor stations. 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.

The unique operating characteristics of compressor stations may support more frequent monitoring of compressor stations as compared to well sites. The collection of fugitive emissions components located at compressor stations are subject to vibration and temperature cycling. Some studies indicate that components subject to vibration, high use, or temperature cycling are the most leak-prone.[57] The EPA best practices guide for LDAR states that more frequent monitoring should be implemented for components that contribute most to emissions.[58] 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.’’ [59]

Additionally, information was also provided by one stakeholder that indicates the operating mode of the compressor(s) located at the station was a key piece of information when detecting fugitive emissions.[60] For instance, the stakeholder stated that when compressors were in standby mode, the detected fugitive emissions were lower. We had not previously considered that compressors may not be 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. If the operating mode of individual compressors has an impact on the occurrence of fugitive emissions, it may provide support for more frequent monitoring, or, alternatively, a requirement to monitor when compressors are operating reflective of normal operating conditions. For example, if the EPA were to move to an annual monitoring frequency, owners and operators might conduct fugitive emissions monitoring during scheduled maintenance periods such as times when there is less demand on the station. This might present the appearance of lower fugitive emissions than if the monitoring occurred during peak seasons, thus decreasing the effectiveness of the program for controlling fugitive emissions, unless the monitoring procedure can assure that does not occur. The EPA is soliciting comment related to the effect the compressor operating mode has on fugitive emissions and comment on a requirement to conduct monitoring only during times that are representative of operating conditions for the compressor station.

There are a number of important factors to consider when selecting the appropriate monitoring frequency for fugitive emissions components located at compressor stations such as the operating modes that likely affect the number and magnitude of fugitive emissions and costs. In light of the concerns from the petitioners that less frequent monitoring than the current requirement of quarterly monitoring would be appropriate, 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 compressor station model plant at quarterly, semiannual, and annual monitoring frequencies. We applied the two approaches used in the 2016 NSPS OOOOa (single and multipollutant approaches) [61] for evaluating cost-effectiveness of these three monitoring frequencies for the fugitive emissions program for reducing both methane and VOC emissions from non-low production well sites. In addition to evaluating the total cost-effectiveness of the different monitoring frequencies, the EPA also estimated the incremental costs of going from the baseline of no monitoring to annual, from annual to semiannual, and from semiannual to quarterly. The incremental cost of control provides insight into how much it costs to achieve the next increment of emission reductions going from one stringency level to the next, more stringent level, and thus is an appropriate tool for distinguishing among the effects of different stringency levels. Table 3 summarizes the total and incremental costs of control for each of the monitoring frequencies evaluated at compressor stations. Additional information regarding the cost of control and emission reductions is available in section 2.5 of the TSD located at Docket ID No. EPA–HQ–OAR–2017–0483.

TABLE 3—NATIONWIDE EMISSIONS REDUCTION AND COST IMPACTS OF CONTROL FOR FUGITIVE EMISSIONS COMPONENTS LOCATED AT COMPRESSOR STATIONS

[Year 2015]

Frequency	Capital cost (million $)	Annualized costs without recovery credits (million $/yr)	Emissions reduction, methane (tpy)	Emissions reduction, VOC (tpy)	Total cost-effectiveness without recovery credit ($/ton methane)	Total cost-effectiveness without recovery credit ($/ton VOC)	Incremental cost-effectiveness without recovery credit ($/ton methane)	Incremental cost-effective-ness without recovery credit ($/ton VOC)
Annual	0.42	2.05	3,680	850	550	2,410		
Semiannual	0.42	3.6	5,510	1,270	650	2,830	840	3,650
Quarterly	0.42	6.7	7,350	1,700	910	3,950	1,690	7,300

[57] Canadian Association of Petroleum Producers, ‘‘Best Management Practice. Management of Fugitive Emissions at Upstream Oil and Gas Facilities,’’ January 2007.

[58] U.S. Environmental Protection Agency, ‘‘Leak Detection and Repair: A Best Practices Guide,’’ EPA–305–D–07–001, October 2007.

[59] Canadian Association of Petroleum Producers, ‘‘Best Management Practice. Management of Fugitive Emissions at Upstream Oil and Gas Facilities,’’ January 2007.

[60] 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.

[61] 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 stepped (semiannual for 2 years followed by annual).

We continue to recognize the limitations in our emissions estimation method, as described for non-low production well sites. As mentioned above, we recognize the distinct operational characteristics of compressor stations that may cause increased fugitive emissions may support more frequent monitoring than proposed for well sites. At this time, we recognize that our analysis likely overestimates the emission reduction and therefore, the cost-effectiveness of each of the three monitoring frequencies for compressor stations due to the same uncertainties described previously for non-low production well sites (*e.g.,* assumed constant percentage of fugitive emissions, uncertainties regarding emission reductions achieved, etc.). Due to these uncertainties, we are unable to conclude that quarterly monitoring is cost-effective for compressor stations, thus we are co-proposing semiannual monitoring for compressor stations. The EPA is soliciting comment and information that will allow us to further refine our model plant analysis, including information regarding emission reductions and the relationship to monitoring frequencies. We are soliciting comment on quarterly monitoring, and our analysis of the factors that may contribute to increased fugitive emissions at compressor stations. 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.

Finally, the EPA is also noting that another stakeholder presented an analysis of third party studies and reports as justification for annual monitoring at compressor stations.[62] In their analysis, the stakeholder states that the EPA has underestimated the control effectiveness of annual OGI monitoring and overestimated emissions from fugitive emissions components at compressor stations. For example, the stakeholder states that annual OGI monitoring at compressor stations can achieve 80 percent emissions reductions, compared to the EPA's estimate of 40 percent emissions reductions. Additionally, the stakeholder compares the EPA model plant emission estimates to measurement data reported under the requirements of 40 CFR part 98, subpart W—Petroleum and Natural Gas Systems (''Subpart W'') as compiled and described in the Pipeline Research Council International, Inc. (PRCI) study report.[63] The EPA has reviewed the information and analyzed the referenced third-party reports to determine if the information would support annual monitoring. The EPA has several concerns with the analysis and conclusions presented by the stakeholder, as discussed in the memorandum describing our analysis,[64] therefore, the EPA is unable at this point to conclude that this information supports annual monitoring for compressor stations. We are co-proposing semiannual and annual monitoring for compressor stations, and soliciting comment and supporting information related to our analysis of the information, including data that sheds further light on which monitoring frequency (annual, semiannual, or quarterly) is most appropriate.

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.[65] As explained in that action, such separate requirements were warranted due to the area's extreme cold temperature, which is below the temperatures at which 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[66] 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.

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[67] 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.[68] 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,[69] 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.[70] 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.[71] 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

[62] See ''Methane Emissions from Natural Gas Transmission and Storage Facilities: Review of Available Data on Leak Emission Estimates and Mitigation Using Leak Detection and Repair'', prepared for INGAA by Innovative Environmental Solutions, Inc., June 8, 2018 and ''Supplement to INGAA White Paper on Subpart OOOOa TSD Estimates of Leak Emissions and LDAR Performance'', from Jim McCarthy and Tom McGrath, Innovative Environmental Solutions, Inc., June 20, 2018 located at Docket ID No. EPA–HQ–OAR–2017–0473.

[63] GHG Emission Factor Development for Natural Gas Compressors, PRCI Catalog No. PR–312–1602–R02, April 18, 2018.

[64] See memorandum *EPA Analysis of Fugitive Emissions Data Provided by INGAA* located at Docket ID No. EPA–HQ–OAR–2017–0483. August 21, 2018.

[65] 83 FR 10628.

[66] Startup of production is defined in 40 CFR 60.5430a.

[67] See Docket ID No. EPA–HQ–OAR–2010–0505–7682.

[68] See Docket ID No. EPA–HQ–OAR–2010–0505–12434.

[69] See FLIR Systems, Inc. product specifications for GF300/320 model OGI cameras at *http://www.flir.com/ogi/display/?id=55671.*

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

[71] 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.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2010–0505; FRL–9929–75–OAR]

RIN 2060–AS30

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

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This action proposes to amend the new source performance standards (NSPS) for the oil and natural gas source category by setting standards for both methane and volatile organic compounds (VOC) for certain equipment, processes and activities across this source category. The Environmental Protection Agency (EPA) is including requirements for methane emissions in this proposal because methane is a greenhouse gas (GHG), and the oil and natural gas category is currently one of the country's largest emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations. The EPA is proposing both methane and VOC standards for several emission sources not currently covered by the NSPS and proposing methane standards for certain emission sources that are currently regulated for VOC. The proposed amendents also extend the current VOC standards to the remaining unregulated equipment across the source category and additionally establish methane standards for this equipment. Lastly, amendments to improve implementation of the current NSPS are being proposed which result from reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the August 16, 2012, final NSPS for the oil and natural gas sector and related amendments. Except for the implementation improvements and the setting of standards for methane, these amendments do not change the requirements for operations already covered by the current standards.

DATES: Comments. Comments must be received on or before November 17, 2015. 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 November 17, 2015. The EPA will hold public hearings on the proposal. Details will be announced in a separate announcement.

ADDRESSES: Submit your comments, identified by Docket ID Number EPA–HQ–OAR–2010–0505, to the Federal eRulemaking Portal: *http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or withdrawn. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. 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 *http://www2.epa.gov/dockets/commenting-epa-dockets.*

Instructions: All submissions must include agency name and respective docket number or Regulatory Information Number (RIN) for this rulemaking. Direct your comments to Docket ID Number EPA–HQ–OAR–2010–0505. 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 *www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be confidential business information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *www.regulations.gov* or email. (See section III.B below for instructions on submitting information claimed as CBI.) The *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 submit an electronic comment through *www.regulations.gov,* 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. If you send an email comment directly to the EPA without going through *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. Electronic files should avoid the use of special characters, 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: *www.epa.gov/epahome/dockets.htm.*

Docket: The EPA has established a docket for this rulemaking under Docket ID Number EPA–HQ–OAR–2010–0505. All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the EPA Docket Center, EPA WJC West Building, Room Number 3334, 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.

FOR FURTHER INFORMATION CONTACT: For information concerning this action, or for other information concerning the EPA's Oil and Natural Gas Sector regulatory program, contact Mr. Bruce Moore, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–5460; facsimile number: (919) 541–3470; email address: *moore.bruce@epa.gov.*

SUPPLEMENTARY INFORMATION: *Outline.* The information presented in this preamble is organized as follows:

technique, therefore, these impacts were not analyzed.

In light of the above, we find that the BSER for reducing methane emissions from continuous bleed natural gas-driven pneumatic controllers in the production and transmission and storage segment and VOC emissions from the remaining unregulated pneumatic controllers (i.e., those in the transmission and storage segment) would be the installation of low-bleed pneumatic controllers. This is the same BSER we identified in the 2012 final rule for reducing VOC emissions from pneumatic controllers in the production and processing segments.

Accordingly, we are proposing a methane emission standard for continuous-bleed, natural gas-driven pneumatic controllers in the production and transmission and storage segment to be a natural gas bleed rate of less than or equal to 6 scfh. We are also proposing a VOC emissions standard for continuous-bleed, natural gas-driven pneumatic controllers in the transmission and storage segment to be a natural gas bleed rate of less than or equal to 6 scfh. As described above, the proposed methane and VOC standards would be the same as the current VOC standards for pneumatic controllers in the production segment in the NSPS.

It is important to note that these costs are most likely over-estimates because they do not take into account the cost savings that would result based on the value of natural gas saved. Therefore, the above cost estimated, which we have already found to be reasonable, represent a conservative scenario and that the cost of these controls are lower in most instances.

For the processing segment, which comprises pneumatic controllers at natural gas processing plants, we identified instrument air systems and replacement of high-bleed controllers with low-bleed controllers as control options for reducing methane emissions from pneumatic controllers.[67] These are the same options we identified for the 2012 rule to reduce VOC emissions from these pneumatic controllers. As described below, we first evaluated the cost of an instrument air system to reduce methane emissions. Since we found these costs to be reasonable (as discussed below), we did not evaluate the costs of replacing the high-bleed pneumatic controllers with low-bleed controllers because the replacement option would result in less methane emission reduction than the instrument air option.

The annual costs of the instrument air system per gas processing plant without considering the cost savings realized from the recovered gas are $11,090, and $7,676 when considering these savings. See the 2012 Supplemental TSD[68] for details of these calculations.

We evaluate the cost of using an instrument air system to reduce methane emissions from the pneumatic controllers at gas processing plants based on the two approaches identified earlier in this section for considering the cost of a multipollutant control (in this case the instrument air system). Under the single pollutant approach, which assigns all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced, we would find the cost of control reasonable if it is reasonable for reducing one pollutant alone. In the 2012 NSPS rulemaking, we already determined that the cost of this control for reducing VOC emissions alone is reasonable for pneumatic controllers at gas processing plants (76 FR 52760). Having assigned all the cost to VOC, the cost of methane reduction would be zero and therefore clearly reasonable. If we assign all the cost to methane instead, it is $738 per ton without considering cost savings and $506 per ton considering cost savings. These costs do not appear excessive, nor do we have reason to believe that they are beyond what the industry can bear. In light of the above, we find the cost of reducing methane emissions from the pneumatic controllers at gas processing plants to be reasonable under the single pollutant approach.

The second approach is to evaluate the cost on a multipollutant basis, based on the percentage reduction expected of VOC and methane. We estimate that replacing high-bleed pneumatic controllers with a non-natural gas driven pneumatic controller (i.e., instrument air-powered) reduces methane emissions by 15 tpy and VOC emissions by 4.2 tpy at gas processing plants. Refer to the 2012 TSD for details of these calculations. Because the control achieves the same reduction for both methane and VOC, under this approach, we apportion the cost equally, resulting in a cost of control of $369 per ton of methane reduced without considering gas savings. Considering gas savings, the cost of control is $253 per ton of methane. These costs do not appear excessive, nor do we have reason to believe that they are beyond what the industry can bear.

With respect to the VOC control cost under this approach, as mentioned above, in the 2012 NSPS rulemaking, we already determined that the cost of this control for reducing VOC emissions alone is reasonable for pneumatic controllers at gas processing plants (76 FR 52760). The cost of VOC reduction under the multiple pollutant approach would be half of that cost and therefore clearly reasonable. In light of the above, we find the cost of reducing methane emissions from pneumatic controllers at gas processing plants to be reasonable as well under the multi-pollutant approach. As mentioned above, we did not identify any nonair quality or energy impacts associated with this control option, therefore no impacts were analyzed.

Based on the above considerations, we propose that pneumatic controllers powered by an instrument air system are the BSER for reducing methane emission from pneumatic controllers at gas processing plants. This is the same BSER we identified for reducing VOC emissions from pneumatic controllers at gas processing plants in the 2012 final rule.

For the reasons discussed above and in the TSD, we have determined that BSER for reducing methane emissions from pneumatic controllers in the processing segment to be instrument air-activated controllers which represent an emission rate of zero for methane. Accordingly, we are proposing a methane standard for pneumatic controllers in the processing segment to be a natural gas bleed rate of zero. This is the same as the VOC standard for these pneumatic controllers in the 2012 NSPS.

We have identified situations where high-bleed controllers are necessary due to functional requirements, such as positive actuation or rapid actuation. An example would be controllers used on large emergency shutdown valves on pipelines entering or exiting compression stations. The current NSPS takes this into account by exempting pneumatic controllers from meeting the applicable emission standards if compliance would pose a functional limitation due to their actuation response time or other operating characteristics. We propose to similarly exempt pneumatic controllers from meeting the proposed methane standard if compliance would pose a functional limitation due to their actuation response time or other operating characteristics.

[67] In the 2012 NSPS, EPA established VOC standards for pneumatic controllers at natural gas processing plants. We are not reopening up those standards in this proposed rule.

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

emissions reduction percentage for each of the combinations of monitoring frequency and repair threshold.

We also looked at the costs of a monitoring and repair program under various monitoring frequencies and repair thresholds (for Method 21), including the cost of OGI monitoring survey, repair, monitoring plan development, and the cost-effectiveness of the various options.[101] For purposes of this action, we have identified in section VIII.A two approaches (single and multipollutant approaches) for evaluating the cost-effectiveness of a multipollutant control, such as the fugitive emissions monitoring and repair programs identified above for reducing both methane and VOC emissions. As explained in that section, we believe that both the single and multipollutant approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be warranted as long as it is such under either of these two approaches.

Under the first approach (single pollutant approach), we assign all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced. Under the second approach (multipollutant approach), we allocate the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. In the multipollutant approach, since methane and VOC emissions are controlled proportionally equal, half the cost is apportioned to the methane emission reductions and half the cost is apportioned to the VOC emission reductions. In this evaluation, we evaluated both approaches across the range of identified monitoring survey options: OGI monitoring and repair performed quarterly, semiannually and annually; and Method 21 performed quarterly, semiannually and annually, with a fugitive emissions repair threshold of 500, 2,500 and 10,000 ppm at each frequency. The calculation of the costs, emission reductions, and cost of control for each option are explained in detail in the TSD. 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 monitoring frequency.

As shown in our TSD, both OGI and Method 21 monitoring survey methodologies costs generally increase with increasing monitoring frequency (i.e., quarterly monitoring has a higher cost of control than annual monitoring). For EPA Method 21 specifically, the cost also increases with decreasing fugitive emissions repair threshold (i.e., 500 ppm results in a higher cost of control than 10,000 ppm). However, as shown in the TSD, the cost of control based on the OGI methodology for annual, semiannual, and quarterly monitoring frequencies for a model well site are estimated to be more cost-effective than Method 21 for those same monitoring frequencies.[102] We therefore focus our BSER analysis based on the use of OGI.

For the reasons stated below, we find that the control cost based on quarterly monitoring using OGI may not be cost-effective based on the information available. As shown in the TSD, under the single pollutant approach, if all costs are assigned to methane and zero to VOC reduction, the cost is $3,753 per ton of methane reduced, and $3,521 per ton if savings of the natural gas recovered is taken into account. If all costs are assigned to VOC and zero to methane reduction, the cost is $13,502 per ton of VOC reduced, and $12,668 per ton if savings of the natural gas recovered is taken into account. Under the multipollutant approach, the cost of control for VOC based on quarterly monitoring is $6,751 per ton, and $6,334 per ton of VOC reduced if savings are considered. In a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], we had concluded that a VOC control option was not cost-effective at a cost of $5,700 per ton. In light of the above, we find that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions under either approach. Having found the control cost using OGI based on quarterly monitoring not to be cost-effective, we now evaluate the control cost based on annual and semi-annual monitoring using OGI. As shown in the TSD, the costs between annual and semi-annual monitoring are comparable. Because semi-annual monitoring achieves greater emissions reduction, we focus our analysis on the cost based on semi-annual monitoring.

While the cost appears high under the single pollutant approach, we find the costs to be reasonable under the multipollutant approach for the following reasons. As shown in the TSD, for VOC reduction, the cost is $4,979 per ton; when savings of the natural gas recovered are taken into account, the cost is reduced to $4,562 per ton. For methane reduction, the control cost is $1,384 per ton; when cost savings of the natural gas recovered is taken into account, the cost is reduced to $1,268 per ton. As explained above, we believe that we have underestimated the emissions from these well sites; therefore, we believe the use of OGI is more cost-effective than the amount presented here. Furthermore, while being used to survey fugitive components at a well site, the OGI may potentially help an owner and operator detect and repair other sources of visible emissions not covered by the NSPS. One example would be an intermittently acting pneumatic controller that is stuck open. The OGI could help the owner and operator detect and address and reduce such inadvertent emissions, resulting in more cost saving from more natural gas recovered.

We also identified in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For monitoring and repair of fugitive emissions at well sites, we believe that the total revenue analysis is more appropriate than the capital expenditure analysis and therefore we did not perform the capital expenditure analysis. For the total revenue analysis, we used the revenues for 2012 for NAICS 211111, 211112 and 213112, which we believe are representative of the production segment. The total annualized costs for complying with the proposed standards is 0.085 percent of the total revenues, which is very low.

For all types of affected facilities in the production, the total annualized costs for complying with the proposed standards is 0.13 percent of the total revenues, which is also very low.

For the reasons stated above, we find the cost of monitoring and repairing fugitive emissions at well sites based on semi-annual monitoring using OGI to be reasonable. To ensure that no fugitive emissions remain, a resurvey of the repaired components is necessary. We expect that most of the repair and resurveys are conducted at the same time as the initial monitoring survey while OGI personnel are still on-site. However, there may be some components that cannot not be repaired right away and in some instances not until after the initial OGI personnel are no longer on site. In that event, resurvey with OGI would require rehiring OGI personnel, which would make the resurvey not cost effective. On the other hand, as shown in TSD, the cost of conducting resurvey using Method 21 is $2 per component, which is reasonable.

[101] See pages 68–69 of the TSD.

[102] See the 2015 TSD for full comparison.

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 9 and 60

[EPA–HQ–OAR–2007–0011; FRL–9672–3]

RIN 2060–AN72

Standards of Performance for Petroleum Refineries; Standards of Performance for Petroleum Refineries for Which Construction, Reconstruction, or Modification Commenced After May 14, 2007

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule; lift stay of effective date.

SUMMARY: On June 24, 2008, the EPA promulgated amendments to the Standards of Performance for Petroleum Refineries and new standards of performance for petroleum refinery process units constructed, reconstructed or modified after May 14, 2007. The EPA subsequently received three petitions for reconsideration of these final rules. On September 26, 2008, the EPA granted reconsideration and issued a stay for the issues raised in the petitions regarding process heaters and flares. On December 22, 2008, the EPA addressed those specific issues by proposing amendments to certain provisions for process heaters and flares and extending the stay of these provisions until further notice. The EPA also proposed technical corrections to the rules for issues that were raised in the petitions for reconsideration. In this action, the EPA is finalizing those amendments and technical corrections and is lifting the stay of all the provisions granted on September 26, 2008 and extended until further notice on December 22, 2008.

DATES: The stay of the definition of ''flare'' in 40 CFR 60.101a, paragraph (g) of 40 CFR 60.102a, and paragraphs (d) and (e) of 40 CFR 60.107a is lifted and this final rule is effective on November 13, 2012. The incorporation by reference of certain publications listed in the final rule is approved by the Director of the Federal Register as of November 13, 2012.

ADDRESSES: The EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2007–0011. All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the EPA Docket Center, Standards of Performance for Petroleum Refineries Docket, EPA West Building, Room 3334, 1301 Constitution Ave. 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 Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Brenda Shine, Office of Air Quality Planning and Standards, Sector Policies and Programs Division, Refining and Chemicals Group (E143–01), Environmental Protection Agency, Research Triangle Park, NC 27711, telephone number: (919) 541–3608; fax number: (919) 541–0246; email address: *shine.brenda@epa.gov.*

SUPPLEMENTARY INFORMATION: The information in this preamble is organized as follows:

I. General Information

A. Does this action apply to me?

Categories and entities potentially regulated by these final rules include:

Category	NAICS Code [1]	Examples of regulated entities
Industry	32411	Petroleum refiners.
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. To determine whether your facility would be regulated by this action, you should examine the applicability criteria in 40 CFR 60.100 and 40 CFR 60.100a. If you have any questions regarding the applicability of this action to a particular entity, contact the person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

particular group of sources in a particular location.

Additionally, those four sources subject to the Billings/Laurel FIP demonstrate compliance with the 150 lb SO_2/3-hour emission limit by measuring the total sulfur concentration and volumetric flow rate of the gas stream at the inlet to the flare. See 40 CFR 52.1392(d)(2)(ii), (e)(2)(ii), (f)(2)(ii), (g)(2)(ii) and (h). Since the FIP must include emissions limits that insure attainment and maintenance of the NAAQS in the Billings/Laurel area, it was appropriate, in setting the standards for the Billings/Laurel FIP, to conservatively assume that 100 percent of the sulfur in the gases discharged to the flare is converted to SO_2, and based on this conversion, set the numeric limit as a value that is not to be exceeded. However, that same assumption is not appropriate when setting national standards for flares. Instead, we must consider the many factors affecting the formation of SO_2 at the flare tip and how these factors affect how much of the sulfur in the gases sent into the flare actually converts to SO_2. Therefore, although setting such source-specific limits was appropriate to satisfy what the modeling showed was necessary to meet the SO_2 NAAQS in the Billings/Laurel area, a different analysis and standard is appropriate for a national rulemaking.

Therefore, for the reasons discussed above, the EPA is finalizing this collective set of CAA section 111(h)-compliant standards for flares, based on our interpretation of CAA section 111(h) as it applies to flares.

Comment: Numerous commenters asserted that the long-term 60 ppmv H_2S fuel gas concentration limit is not cost effective for flares and, therefore, not BSER for flares. The commenters noted that the EPA did not include costs for compressors, additional amine units and sulfur recovery units, and one commenter stated that the EPA did not consider the range of costs that are incurred by individual refineries. Commenters also asserted that the EPA overstated emission reductions by using 162 ppmv H_2S as a baseline because many refinery streams currently sent to the flare contain H_2S concentrations below 162 ppmv, so 162 ppmv H_2S does not reflect long-term performance. Commenters noted that the British thermal units (Btu) content of flare gas is highly variable and generally lower than that used by the EPA, so the EPA's analysis overestimated the value of the recovered flare gas. One commenter noted that the EPA should have considered consent decree requirements in the baseline SO_2 emissions estimates.

One commenter stated that the long-term 60 ppmv H_2S fuel gas concentration limit could preclude some refineries from processing high-sulfur crude oils, thereby limiting refining production capacity. Another commenter noted that many flares will receive both fuel gas and process upset gas, so it would be impossible to determine if an exceedance is caused by the regulated fuel gas or by the exempt gas. The commenter recommended that the EPA apply the long-term 60 ppmv H_2S fuel gas concentration limit only to fuel gas combusted in process heaters, boilers and similar fuel gas combustion devices, and not to flares, or that the EPA allow Alternative Monitoring Plans to demonstrate compliance with the emissions limits for non-exempt gas streams upstream of the flare header.

Response: We acknowledge that, at proposal, we determined that a long-term 60 ppmv H_2S fuel gas concentration limit was cost effective primarily for process heaters, boilers and other fuel gas combustion devices that are fed by the refinery's fuel gas system. Based on the typical configuration at a refinery, adding one new fuel gas combustion device to the fuel gas system would essentially require the owner or operator to limit the long-term concentration of H_2S in the entire fuel gas system to 60 ppmv, so emission reductions would result from all fuel gas combustion devices tied to that fuel gas system. Upon review of the BSER analysis conducted at proposal for fuel gas combustion devices, we now realize that the analysis is not applicable to flares (See Docket Item No. EPA–HQ–OAR–2007–0011–0289).

Moreover, since we are regulating flares separately from other fuel gas combustion devices in this final rule, we should separately consider whether a long-term H_2S concentration limit is appropriate for fuel gas sent to flares.

In developing the suite of CAA section 111(h) standards for flares, we considered whether refineries should be required to optimize management of their fuel gas by limiting the long-term H_2S concentration to 60 ppmv in addition to the short-term H_2S concentration of 162 ppmv during normal operating conditions. We determined that, for refineries to demonstrate that their fuel gas complies with a long-term H_2S concentration of 60 ppmv, refineries would have to install a flare gas recovery system (which was not needed for other fuel gas combustion devices) and then upgrade the fuel gas desulfurization system. Alternatively, refineries would have to treat the recovered fuel gas to limit the long-term concentration of H_2S to 60 ppmv with new amine treatment units on each flare.

While some of the costs provided by the commenters did not include the value of the recovered gas and appeared, at times, to include equipment not necessarily required by the regulation, we generally agree with the commenters, based on our own cost estimates, that optimizing management of the fuel gas system to limit the long-term concentration of H_2S to 60 ppmv is not cost effective for flares (see Table 4 below). We note that the costs provided by the commenters and the costs and emissions reductions in our analysis are the incremental costs and emissions reductions of going from the short-term 162 ppmv H_2S concentration to a combined short-term 162 ppmv H_2S concentration and long-term 60 ppmv H_2S concentration. While we are aware that some consent decrees require refineries to limit the concentration of H_2S in the fuel gas to levels lower than the short-term 162 ppmv H_2S concentration, our baseline when evaluating the impacts of a national standard (in this case, 40 CFR part 60, subpart Ja) is the national set of requirements to which an affected flare would be subject in the absence of subpart Ja (*i.e.,* the short-term 162 ppmv H_2S concentration limit in 40 CFR part 60, subpart J).

TABLE 4—NATIONAL FIFTH YEAR IMPACTS OF MEETING A LONG-TERM 60 PPMV H_2S CONCENTRATION FOR FLARES SUBJECT TO 40 CFR PART 60, SUBPART JA

	Capital cost ($1,000)	Total annual cost ($1,000/yr) [a]	Emission reduction (tons SO_2/yr) [b]	Emission reduction (tons NO_X/yr) [b]	Emission reduction (tons VOC/yr) [b]	Cost effectiveness ($/ton)
New	80,000	15,000	6	34	130	84,000

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 60 and 63

[EPA–HQ–OAR–2006–0699; FRL–8492–4]

RIN 2060–AN71

Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry; Standards of Performance for Equipment Leaks of VOC in Petroleum Refineries

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: EPA is issuing final amendments to the standards of performance for equipment leaks of volatile organic compounds in the synthetic organic chemicals manufacturing industry and to the standards of performance for equipment leaks of volatile organic compounds in petroleum refineries. The amended standards for the synthetic organic chemicals manufacturing industry apply to affected facilities that are constructed, reconstructed, or modified after January 5, 1981, and on or before November 7, 2006. The amended standards for petroleum refineries apply to affected facilities that are constructed, reconstructed, or modified after January 4, 1983, and on or before November 7, 2006. In this action, EPA is also issuing new standards of performance for equipment leaks of volatile organic compounds in the synthetic organic chemicals manufacturing industry and for equipment leaks of volatile organic compounds in petroleum refineries which apply to affected facilities that are constructed, reconstructed, or modified after November 7, 2006. The final amendments and new standards are based on the results of our review of the existing regulations as required by section 111(b)(1)(B) of the Clean Air Act.

DATES: This final rule is effective on November 16, 2007. The incorporation by reference of certain publications listed in these rules is approved by the Director of the Federal Register as of November 16, 2007.

ADDRESSES: EPA has established a docket for this action under Docket ID No. EPA–HQ–OAR–2006–0699. All documents in the docket are listed in the Federal Docket Management System index at *www.regulations.gov*. Although listed in the index, some information is not publicly available, e.g., Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *www.regulations.gov* or in hard copy at the Air and Radiation Docket, EPA West Building, Room 3334, 1301 Constitution Ave., 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 Air and Radiation Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For information concerning the final amendments and new standards, contact Ms. Karen Rackley, Coatings and Chemicals Group, Sector Policies and Programs Division, Office of Air Quality Planning and Standards (E143–01), Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–0634; fax number: (919) 541–0246; e-mail address: *rackley.karen@epa.gov*. For information concerning compliance and enforcement of the final amendments and new standards, contact Ms. Marcia Mia, Air Compliance Branch, Compliance Assessment and Media Programs Division, Office of Compliance (MC 2223A), Environmental Protection Agency, Washington, DC 20460; telephone number: (202) 564–7042; fax number: (202) 564–0050; and e-mail address: *mia.marcia@epa.gov*.

SUPPLEMENTARY INFORMATION:

Regulated Entities. Categories and entities potentially regulated by this action include:

Category	NAICS code[1]	Examples of potentially regulated entities
Industry	324110	Petroleum refiners.
	Primarily 325110, 325192, 325193, and 325199.	Synthetic organic chemical manufacturing industry (SOCMI) units, e.g., producers of benzene, toluene, or any other chemical listed in 40 CFR 60.489.

[1] North American Industrial Classification Code.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be regulated by this action. To determine whether your facility is regulated by this action, you should examine the applicability criteria in 40 CFR 60.480, 60.590, 60.480a, and 60.590a. If you have any questions regarding the applicability of the final amendments or new standards to a particular entity, contact the people listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

Worldwide Web (WWW). In addition to being available in the docket, an electronic copy of the final rule is available on the WWW through the Technology Transfer Network (TTN). Following signature, EPA will post a copy of the final rule on the TTN's policy and guidance page for newly proposed or promulgated rules at *http://www.epa.gov/ttn/oarpg*. The TTN provides information and technology exchange in various areas of air pollution control.

Judicial Review. Under section 307(b) of the Clean Air Act (CAA), judicial review of the final rule is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by January 15, 2008. Under section 307(d)(7)(B) of the CAA, only an objection to the final rule that was raised with reasonable specificity during the period for pubic comment can be raised during judicial review. Moreover, under section 307(b)(2) of the CAA, the requirements established by this final rule may not be challenged separately in any civil or criminal proceedings brought by EPA to enforce these requirements.

Section 307(d)(7)(B) of the CAA further provides that "[O]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review." This section also provides a mechanism for us to convene a proceeding for reconsideration, "[i]f the person raising an objection can demonstrate to the EPA that is was impracticable to raise such objection within [the period for public comment] or if the grounds for such objection arose after the period for public comment (but within the time includes the requirements in 40 CFR part 60, subpart GGG, as amended. Affected facilities must comply with the requirements in new subpart VVa of 40 CFR part 60, except for the monitoring requirements applicable to connectors.

III. Rationale for Changes Since Proposal

A. How did EPA develop new standards for 40 CFR part 60, subparts VVa and GGGa?

Five sources of information were considered in reviewing the appropriateness of the current NSPS requirements for new sources: (1) Applicable Federal regulations; (2) applicable state and local regulations; (3) data from National Enforcement Investigations Center (NEIC) inspections; (4) emissions data provided by industry representatives; and (5) petroleum refinery consent decrees. (A significant number of refineries, representing about 77 percent of the national refining capacity, are subject to consent decrees that limit the emissions from 40 CFR part 60, subpart GGG process units.) Once we identified leak definitions for various equipment types, we evaluated these leak definitions in conjunction with technical feasibility, costs, and emission reductions to determine BDT for each type of equipment.

The cost methodology incorporates the calculation of annualized costs and emission reductions associated with each of the options presented. Cost-effectiveness is the annualized cost of control divided by the annual emission reductions achieved. For NSPS regulations, the standard metric for expressing costs and emission reductions is the impact on all affected facilities accumulated over the first 5 years of the regulation. Details of the calculations can be found in the public docket (EPA–OAR–HQ–2006–0699). Our BDT determinations took all relevant factors into account, including cost considerations.

For each of the new standards, the predominant method used to reduce emissions from equipment leaks is the work practice of an LDAR program that includes periodic monitoring of equipment using EPA Method 21. This method has been used for more than 20 years to detect leaks and is currently the most widely-used test method. However, other approved methods may be used to detect leaks.

We also considered an equipment standard requiring installation of "leakless" equipment. "Leakless" equipment, such as diaphragm valves, is less likely to leak than standard equipment, but leaks may still develop. Therefore, monitoring or other type of observation is appropriate to ensure that leaks are caught if they develop. In addition, these types of equipment may not be suitable for all possible process operating temperatures, pressures, and fluid types. We could not identify any new "leakless" technologies that could be applied in all applications. Therefore, requiring "leakless" equipment is not technically feasible and this option was not considered to be BDT for SOCMI or petroleum refining sources. We note that 40 CFR part 60, subpart VV does include provisions for equipment designed for no detectable emissions, so owners or operators that do replace existing equipment with "leakless" equipment have options for compliance.

1. Leak Definitions for Pumps and Valves

We previously demonstrated that leak definitions of 2,000 ppm for pumps and 500 ppm for valves are BDT in the preamble to the proposed amendments to 40 CFR part 60, subparts VV and GGG (November 7, 2006, 71 FR 65305, with additional discussion at 71 FR 65308). Since proposal, the cost-effectiveness values for this new requirement have changed slightly based on changes to the assumptions used to develop emission estimates; section V of this preamble includes details on the specific changes. For SOCMI, the estimated emission reductions are 94 tons of VOC per year at a cost savings of $380/ton. For petroleum refineries, the estimated emission reductions are 13 tons of VOC per year at a cost of $1,600/ton. The cost to achieve these emission reductions is still considered to be reasonable; therefore, we maintain our original conclusion that EPA Method 21 monitoring of pumps and valves and repair of leaks above 2,000 ppm for pumps and 500 ppm for valves is BDT.

We have also evaluated the cost-effectiveness of lowering the leak definitions even further for valves because there are some state rules and petroleum refinery consent decrees at lower levels. The results of that analysis show that an LDAR program for valves at a leak definition lower than 500 ppm is not cost-effective. The analysis shows emission reductions of 26 tons of additional VOC per year at a cost-effectiveness of $5,700/ton for SOCMI and emission reductions of 8 tons of additional VOC per year at a cost-effectiveness of $16,000/ton for refineries. The additional VOC emission reductions at a leak definition lower than 500 ppm is not cost-effective. The results of the impacts analysis is provided in the docket (Docket ID No. EPA–HQ–OAR–2006–0699).

We decided not to consider a lower leak definition for pumps because we do not have evidence that it will achieve significant emission reductions at reasonable cost and because such a requirement would impose an unwarranted increase in the compliance burden. No other Federal or state rules require repair of pumps with leaks below 2,000 ppm, and concerns have been expressed in the past that repair of pumps with lower concentrations could result in significant and costly maintenance. We also cannot estimate the emission reductions because we are unsure how effective repairs will be for pumps with low leak concentrations. In addition, many facilities that will be subject to the new standards have other process units that are subject to other standards. Including a leak definition in the new standards that differs from the leak definitions in all other rules would make compliance more challenging at such facilities and unnecessarily increase the potential for inadvertent errors.

We also did not consider increasing the number of times per year that valves and pumps must be monitored. Valves and pumps are already subject to monthly monitoring. The cost to monitor more frequently would outweigh the possible emission reductions. Additionally, pumps are subject to weekly inspections for indications of liquids dripping. Therefore, the monitoring frequency was not changed and is still considered BDT.

2. Other New Standards in 40 CFR Part 60, Subpart VVa

Connector Monitoring. The current NSPS in 40 CFR part 60, subpart VV limits VOC emissions from connectors by specifying that if a potential leak is found by visual, audible, olfactory, or any other detection method, the owner or operator must eliminate the indications of the potential leak or monitor the connector to determine whether the potential leak is leaking VOC greater than 10,000 ppm. If the potential leak is actually a leak, it must be repaired. When the current NSPS were promulgated, we concluded that this procedure would reduce emissions by correcting major leaks.

After consideration of current operating practices, we concluded that repairing connector leaks as they are discovered is still the predominant method for reduction of VOC from connectors. However, during our review of the current requirements, we found a