January 31, 2022

Submitted via www.regulations.gov

The Honorable Michael Regan
Administrator
Environmental Protection Agency
1200 Pennsylvania Avenue, NW
Washington, D.C. 20460

Re: ***Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (RIN 2060-AV16)***

Dear Administrator Regan:

The American Exploration and Production Council (AXPC) appreciates the opportunity to provide input on the Environmental Protection Agency's (EPA) publication, "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review (RIN 2060-AV16)" (Initial Methane Notice) published on November 15, 2021 (86 Fed. Reg. 63,110). AXPC appreciates the importance of regulating methane emissions and looks forward to continuing the robust and productive dialogue with EPA on the oil and natural gas regulations that has been occurring over the past decade.

AXPC is a national trade association representing 28 of the largest independent oil and natural gas exploration and production companies in the United States. AXPC companies are among leaders across the world in the cleanest and safest onshore production of oil and natural gas, while supporting millions of Americans in high-paying jobs and investing a wealth of resources in our communities. Dedicated to safety, science, and technological advancement, our members strive to deliver affordable, reliable energy while positively impacting the economy and the communities in which we live and operate. As part of this mission, AXPC members understand the importance of ensuring positive environmental and public-welfare outcomes and responsible stewardship of the nation's natural resources. The United States is a world leader in oil and natural gas production, achieving that status while at the same time substantially reducing emissions. The historic reductions in US greenhouse gas (GHG) emissions over the last decade have been driven by the emergence of US natural gas production as a low-cost source of reliable energy. It is important that regulatory policy enables us to build on that success. AXPC members support continued progress on both fronts through innovation and collaboration.

AXPC companies are focused on reducing methane emissions from their operations and support effective and reasonable regulation of methane that balances the essential value of US oil and natural gas production with the global challenge of addressing climate change. AXPC companies believe collaboration amongst policy makers and industry partners is needed to find solutions that will meaningfully drive down emissions, while allowing US independent producers to meet the global demand for affordable and reliable oil and natural gas.

Regulation of methane emissions should:

- Encourage innovation and flexibility, instead of command-and-control regulations that hinder the goal of reducing methane emissions
- Allow and incentivize the development and deployment of technologies to monitor and mitigate methane emissions for compliance purposes
- Appropriately quantify and assess the feasibility, costs and benefits of implementing new requirements for existing facilities
- Avoid creating duplicative and overlapping regulatory regimes at the federal and state levels
- Properly interpret and follow the relevant provisions of the Clean Air Act

Consistent with these principles, AXPC is supportive of EPA in keeping the efficiencies in Part 60 of Title 40 of the *Code of Federal Regulations* (40 CFR), subpart OOOOa, that EPA intends to retain, as reflected in the Initial Methane Notice. These efficiencies reduce unnecessary burden without negative environmental impacts – thus increasing the cost-effectiveness of the OOOOa rulemaking.

AXPC is also supportive of EPA's continued support for using emerging technologies that could enhance detection of potential emissions from the oil and natural gas sector. There are significant new technologies that have been developed over the past six years that could be utilized in the oil and natural gas sector. EPA has discretion to allow for multiple alternative forms of work-practice standard, so long as each of the alternatives complies with the statutory requirements.[1] If EPA allows these technologies to be used, operators will be able to identify and correct issues well before periodic site-by-site surveys may find them – resulting in significant emission reductions. AXPC believes that EPA should explicitly allow in this rulemaking for alternative means of compliance, which can also be conceptualized as alternative work-practice standards, rather than relegating all such issues to the AMEL process under Section 111(h)(3). EPA's AMEL process, although significantly improved upon in the 2020 Technical Amendments as discussed below, has historically been extremely complicated as a result of the regulatory requirements, with no alternative certifications being granted thus far. Therefore, having the option to use an alternative technology outside of the statutory AMEL process that will recognize advancement and innovation in this space will be extremely helpful and allow operators to capitalize on these technologies to reduce emissions at competitive costs. AXPC appreciates EPA's effort to introduce an alternative technology pathway. AXPC looks forward to engaging with EPA as this rulemaking continues to ensure that alternative technologies play an appropriate role in improving environmental outcomes.

While AXPC is supportive of many aspects of the Initial Methane Notice as drafted, AXPC is concerned with the technical feasibility and cost-effectiveness of some provisions that EPA, in the Initial Methane Notice, indicates it intends to finalize or otherwise solicits comment on. AXPC provides specific details with regard to these concerns in the attached detailed comments. We look forward to seeing regulatory text and respective definition to help clarify the number of uncertainties and concerns that are provided below.

AXPC appreciates that EPA has already acknowledged that the Initial Methane Notice publication does not constitute a complete proposed rule, as evidenced by EPA's stated commitment to issuing a

[1] *See* 86 Fed. Reg. at 63,197/2 ("proposing an alternative work practice for detecting fugitive emissions").

supplemental proposal at a later date, to include the proposed regulatory text for new subparts OOOOb and OOOOc.

Additionally, AXPC urges EPA in the supplemental proposal to provide that the date for determining whether sources are “new” under OOOOb is not November 15, 2021 (the date of publication in the *Federal Register* of the Initial Methane Notice), but rather the date of publication of the supplemental proposal, to include publication of proposed regulatory text for OOOOb (and OOOOc), which the public has not yet seen.

AXPC is providing detailed comments in the attachment that expands on these general themes as well as many other matters. AXPC appreciates the opportunity to provide these comments and looks forward to working with EPA in its continued development of these rules.

Sincerely,

Anne Bradbury
CEO
American Exploration and Production Council

Attachment: AXPC Specific Comments

cc:
Joe Goffman, EPA Principal Deputy Assistant Administrator for the Office of Air and Radiation (OAR) Performing Delegated Duties of Assistant Administrator
Tomas Carbonell, EPA Deputy Assistant Administrator for Stationary Sources, Office of Air and Radiation
Peter Tsirigotis – EPA OAQPS, Director
David Cozzie – EPA OAQPS Deputy Director, Sector Policies and Programs Division
Karen Marsh, EPA OAQPS, Sectors Policies and Programs Division
Amy Hambrick, EPA OAQPS, Sectors Policies and Programs Division

AXPC SPECIFIC COMMENTS
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ABBREVIATIONS AND ACRONYMS

40 CFR Part 60 subpart OOOOa	**OOOOa**
40 CFR Part 60 subpart OOOOb (not yet finalized)	OOOOb
40 CFR Part 60 subpart OOOOc (not yet finalized)	OOOOc
American Exploration and Production Council	AXPC
Alternative Means of Emission Limitation	AMEL
Audio, visual, and olfactory	AVO
U.S. Environmental Protection Agency	EPA
Best Management Practice(s)	BMP(s)
Carbon Dioxide	CO_2
Carbon Dioxide Equivalent	CO_2e
Clean Air Act	CAA
Code of Federal Regulations	CFR
Destruction Rate Efficient	DRE
Emergency shutdown devices	ESD
Emission Guidelines	EG
Environmental Justice	EJ
Federal Register	Fed. Reg.
Gas Star Partner Reported Opportunities	PROs
Greenhouse gas	GHG
Greenhouse Gas Reporting Program	GHGRP
Hydrogen Sulfide	H_2S
Infrastructure and Investment Jobs Act of 2021	IIJA
Kilograms per hour	Kg/hr
Leak detection and repair	LDAR
Mobile gas lift compressors	MGLC
National Institute for Occupational Safety and Health	NIOSH
New Source Performance Standards	NSPS
New Source Review	NSR
Occupational Safety and Health Administration	OSHA
Optical Gas Imaging	OGI
Professional Engineer	PE(s)

Quality assurance/quality control	QA/QC
Standard cubic feet per minute	Scfm
Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review	Initial Methane Notice
Tons per year	Tpy
U.S. Environmental Protection Agency	EPA
U.S. Bureau of Land Management	BLM
U.S. Pipeline and Hazardous Materials Safety Administration	PHMSA
United States Code	U.S.C.

I. PRESERVING REFORMS FROM THE 2020 TECHNICAL RULE

A. Recordkeeping and Reporting

As a general matter, AXPC urges EPA to minimize any unnecessary recordkeeping and reporting requirements that overlap with those of other state, local, or federal agencies. To the extent that one or more other agencies already require companies to record and report identical or substantially similar information, EPA should deem that recordkeeping and reporting sufficient for purposes of this rulemaking. This should guide EPA's approach both in its retention of the reforms of subpart OOOOa from the 2020 Technical Rule, and in its design of new subparts OOOOb and OOOOc.

Expediting recordkeeping and reporting allows for the oil and natural gas industry to continue to comply with the intent of EPA's regulations, while removing unnecessary burdens that do not result in increasing emissions reductions. Recordkeeping and reporting reforms become even more important as this regulation adds another form of new source (OOOOb) and will eventually result in state plans for all existing sources (OOOOc). As there are multiple regulations that will apply to OOOOc sources, we believe that there is the potential for duplication and unnecessary reporting to multiple regulators.

Also, while AXPC will have comments after seeing the proposed regulatory text in EPA's future actions, AXPC is currently supportive of the recordkeeping and reporting reforms that EPA has implemented since the development of the OOOOa program. It is currently unclear to AXPC without regulatory text what other recordkeeping and reporting reforms may be necessary to harmonize the multiple overlapping federal and state regulations, but we will provide comments within the supplemental proposal comment period.

1. Observation Path

AXPC continues to support removing required observation paths from well sites as equipment on a well site is unlikely to change. By including a description of the walking paths instead of specific observation paths it would eliminate the need for additional recordkeeping and reporting requirements while still providing the level of protection that EPA intends within their rulemaking. It also would not eliminate EPA's or state's abilities to enforce proper leak detection with a description.

2. Leak Detection and Repair

AXPC continues to support the reforms to reporting and recordkeeping for leak detection and repair (LDAR) and believes that the state requirements should be taken into consideration, especially with the requirement for states to develop plans for existing source requirements.

3. Digital Photograph requirement

AXPC still supports removing the requirements related to digital photographs or videos related to optical gas imaging. As EPA has proposed significant changes to collecting and maintaining information for LDAR, we have provided extensive comments below in discussion of Part 60 of Title 40 of the *Code of Federal Regulations* (40 CFR), Appendix K that we believe should also be applied for any OOOOa sources.

B. Alternative Means of Emission Limitation (AMEL) improvements

1. State Equivalency

AXPC supports EPA's recognition of approved state programs that are equivalent to EPA's LDAR requirements and recommends that EPA continue with that allowance. It prevents redundancy of recordkeeping and reporting and allows for those state programs that are more stringent than EPA's to continue.

State equivalency becomes even more important with EPA planning to propose emission guidelines (EGs) that will require state plans. Without allowing for state equivalency, it will make developing and approving state plans more difficult in the future.

2. Emerging Technologies

AXPC supports the multiple reforms that EPA proposes to enhance the AMEL process to allow for emerging technologies and believes that EPA can further enhance those reforms in this rulemaking (see below for additional comments). Specifically, EPA can better establish clear and consistent parameters under which a technology will be able to detect methane emissions and site-specific variables can be addressed in conditions required for the use of the technology.

AXPC also supports the application of approved emerging technologies by EPA to other sources within the oil and natural gas industry. Specifically, **EPA should allow for basin-wide equivalency determinations or basin-wide approvals, once equivalency has been demonstrated, and incorporation by reference of emerging technologies to other sites.**

Finally, **AXPC supports the allowance for modeling and testing at a controlled test environment to demonstrate performance of new technologies.** AXPC also appreciates the allowance for vendors and manufacturers as applicants for approval of emerging technology and not limiting the submissions by oil and natural gas companies with sites. Artificially limiting submissions to oil and natural gas companies limits those that are developing these new and emerging technologies, the experts on each new technology's performance, from working with EPA and other stakeholders to implement the technologies as broadly as possible to lower emissions at a reduced cost.

C. Professional Engineer (PE) Certifications

AXPC supports EPA allowing for in-house engineers to be used for certification as AXPC agrees with EPA assessment that in-house engineers may be more knowledgeable about site design and control than a third-party professional engineer (86 Fed. Reg. 63,162).

Not only are in-house engineers likely to be more knowledgeable about site design but requiring PE certification can unnecessarily raise costs and delays, as there are not enough PEs certified in the required oil and natural gas requirements to support the rulemaking. Thus, if EPA wanted to require PE certification, it would need to provide significantly longer compliance timeframes to support the need to hire and train PEs.

II. Overarching Concerns and Opportunities

A. Date for defining a "new source" for OOOOb

AXPC urges EPA, in its supplemental proposal, to change the applicability date for sources that will be subject to the new subpart OOOOb from November 15, 2021 (the date of publication in the *Federal Register* of the Initial Methane Rule) to the date of publication in the *Federal Register* of the supplemental proposal, which will, apparently, also be the date on which EPA will first propose regulatory text for the new subparts OOOOb and OOOOc.

AXPC's position is that EPA does not have authority under Section 111 to define a "new source" for a standard other than by reference to the date of publication of proposed regulatory text for that standard. Additionally, even if EPA had legal authority to proceed in this manner, there are strong policy and equity reasons why it is not appropriate for EPA to do so.

First, as regards EPA's legal authority to proceed in this manner: Clean Air Act (CAA) Section 111(a)(2) (42 United States Code (U.S.C.) § 7411(a)(2)), provides that a "new source" is any source whose construction or modification begins "after the publication of . . . proposed regulations [] prescribing a standard of performance under this section which will be applicable to such source." The CAA does not define the term "proposed regulations." However, with respect to the new subparts OOOOb and OOOOc, the Initial Methane Notice does not appear to constitute "proposed regulations . . . prescribing a standard" within the meaning of the statute, as that publication does *not* propose regulatory text with respect to these new subparts.

The approach EPA has taken, under which it purports to subject new sources (i.e., those that commence construction or modification after November 15, 2021) to regulatory requirements whose regulatory text it has not yet proposed, creates considerable uncertainty for companies that may wish to construct or modify sources but cannot reasonably predict what specific requirements such sources will be subject to under the new subparts. For this reason, EPA should, in the supplemental proposal, propose an applicability date for new subparts OOOOb and OOOOc of the date of publication of the supplemental proposal (assuming that the supplemental proposal, unlike the Initial Methane Notice, contains proposed regulatory text for these subparts).

Second, even if EPA had legal authority to proceed in this manner, it is unsound as a matter of policy, and inequitable. The plain purpose of Congress defining a new source as one whose construction or modification begins after proposal of regulations is that this sequence allows owners and operators to understand their proposed regulatory obligations when they make decisions whether to break ground on new facilities or modify existing facilities—so that they know, not only whether a source constructed or modified after a date certain will be treated as a new source, but also the details of the regulatory obligations that will be incurred by a source deemed new. Because EPA has not yet proposed regulatory text for new subpart OOOOb, Congress's purpose is not fulfilled if EPA deems sources to be new whose construction or modification begins after November 15, 2021.

In addition to EPA's approach not fulfilling Congress's purpose in enacting 111(a)(2), it also threatens to unjustly penalize owners and operators who have been making and will continue to make choices in good faith as to whether and how to construct or modify their facilities without the benefit of proposed regulatory text.

Finally, even if EPA does not in its supplemental proposal change the date defining a new source from November 15, 2021 to the date of publication in the *Federal Register* of the supplemental proposal and proposed regulatory text—which, for the reasons given above, it should—AXPC urges EPA at a minimum to account for the gap that failing to change this date would create between the "trigger" date for new sources and the date at which regulated companies see proposed regulatory text by providing a longer period to come into compliance, to include a phasing-in of regulatory requirements through a series of compliance dates, similar to the approach taken in the 2016 OOOOa rule.

B. Compliance Dates for OOOOb

As a general matter, AXPC's position is that EPA will need to provide a considerably longer time for compliance with the provisions of new subpart OOOOb after finalization than it otherwise might, or than it has in prior Section 111 rulemakings (AXPC notes that EPA's recent regulations in this sector, to include both the OOOO and OOOOa rulemakings, employed a phasing-in of regulatory requirements through a series of compliance dates). AXPC believes that a longer time for compliance is specifically appropriate here for three main reasons.

First, the subject matter involved in this rulemaking is considerably more complex than it was in most or all prior rulemakings under this section, in terms of, e.g., factors including the scope and types of equipment covered, and the number of sources covered, and the variability from site to site.

Second, ongoing supply-chain issues, including but not limited to, the impact of the ongoing pandemic, make it more difficult for companies to prepare for compliance.

Third, because the Initial Methane Notice did not include proposed regulatory text for new subpart OOOOb, companies are even more hindered in their ability to prepare for their eventual compliance options.

AXPC looks forward to seeing proposed regulatory text for new subpart OOOOb in the forthcoming supplemental proposal. Based on our review of that proposed regulatory text and the information and analysis that the supplemental proposal will provide, we anticipate that we will be able to provide more detailed comments and suggestions with respect to compliance dates in our comments on the supplemental proposal.

C. Social Cost of Greenhouse Gases

AXPC notes that EPA's Initial Methane Notice estimates benefits from the methane emission reductions it projects this rulemaking will cause by using the interim social cost of methane estimates contained in the February 2021 publication from the Interagency Working Group. 86 Fed. Reg. at 63,258/3. AXPC incorporates here by reference the comments on those interim estimates that it filed as part of a multi-trade-group association in June 2021. Those comments are available in the online docket for public comment on those interim estimates, docketed as OMB-2021-0006-0087 (June 21, 2021). Key themes of those comments include, but are not limited to, the need for transparent procedures in establishing social cost estimates, the need for proper peer review, and the importance of communicating the significant uncertainties within the estimates and limiting their use to regulatory impact analysis pursuant to interagency review under Executive Order 12,866.

D. Avoiding duplicative regulation not authorized by statute

AXPC is concerned that, under EPA's Initial Methane Notice, some sources would be deemed both "new" and "existing" with respect to Section 111 standards for methane. Specifically, sources whose construction or modification begins after September 18, 2015, and before November 15, 2021, would be "new" in that they are covered by subpart OOOOa, *and* "existing" in that they will *also* be covered by new subpart OOOOc. 86 Fed. Reg. at 63,117, Table 1 (Applicability Dates for Proposed Subparts Addressed in This Proposed Action). EPA does not have authority to take this approach under the statute. Even if it did, there is no environmental benefit to "pancaking" multiple layers of regulation on the same source, and there are compelling reasons of policy why EPA should not do so—in fact, doing so could be environmentally counterproductive (please note that this is separate and apart from AXPC's position, as expressed elsewhere in these comments, that EPA cannot define a "new source" as one that begins construction or modification after the publication of the Initial Methane Notice, and that it should instead, in the supplemental proposal, set the determining date for new-source status at the eventual date of publication of that supplemental proposal, to include proposed regulatory text for new subparts OOOOb and OOOOc).

First, Section 111(d)(1)(A)(ii) provides that state plans for existing sources establish standards of performance for "any existing source for any air pollutant . . . to which a standard of performance under this section would apply *if such existing source were a new source*" (emphasis added). And Section 111(a)(6) defines "existing source" as "any stationary source *other than a new source*" (emphasis). The plain text of Section 111, therefore, repeatedly draws a binary distinction between new and existing sources. There is no sign that Congress intended EPA to regulate *any* source for the same pollutant simultaneously as both a new source under 111(b) and an existing source under 111(d).

Second, even if EPA did have authority to proceed in this fashion, it would be either pointless or environmentally counterproductive to do so. Layering multiple sets of regulation to control the same pollutant does not provide enhanced environmental benefits, but it does create a highly confusing situation for owners and operators wishing to understand their compliance obligations. In fact, this "pancake" approach could actually lead to worse environmental outcomes. If owners and operators subject to a new-source regulation are faced with the prospect that EPA, at any future time, may also subject their new-source facilities to an *existing* source rule, that uncertainty will deter the owners and operators from innovating to comply with, and even do better than, the standards contained in the new-source regulation. Section 111(b) is supposed to identify the best performance or work-practice standards and encourage their adoption to generally further the performance of the fleet of new sources. That purpose is thwarted under a duplicative, confusing, and extra-statutory approach like the one EPA suggests in the Initial Methane Notice.

Fortunately, there is a way to avoid this negative scenario which is both in keeping with the statute and good policy. In its supplemental proposal, EPA should revise the Initial Methane Notice in the following regard: It should, in the supplemental proposal, propose that new subpart OOOOc will only apply to pre-OOOOa sources, i.e., those sources that did not begin construction or modification before September 18, 2015. This will ensure that new sources subject to OOOOa are not subject to duplicative methane regulation under that standard as well as the existing-source methane rule in new subpart OOOOc. By taking this approach, EPA can avoid both the conflict with the statutory text and design, and the policy problems noted above.

III. FUGITIVE EMISSIONS FROM THE UPSTREAM SECTOR

A. Alternative Screening Using Advanced Measurement Technologies

AXPC is strongly supportive of EPA's consideration of alternative leak detection and repair (LDAR) approaches and technologies as potentially allowable compliance mechanisms comparable to surveys using optical gas imaging (OGI) or EPA Method 21. Advanced, game-changing technologies for detecting methane are rapidly evolving and being deployed in the United States and abroad. These include, but are not limited to, use of airplanes, drones, or onsite "continuous" monitoring sensors, whether used individually or (as is typical) with multiple technologies as part of an overall emissions detection and monitoring system. We believe that there is sufficient evidence to show that several screening and monitoring technologies on the market today are capable of detecting fugitive emissions from affected sources as well as, if not better than, periodic surveys using OGI or EPA Method 21. Further, some technologies have been shown to detect certain types of emissions that OGI has missed, particularly in field deployment comparisons and across larger areas.

However, AXPC has concerns with EPA's singular approach of requiring that the alternative must meet a minimum threshold of 10 kilograms per hour (kg/hr) and be conducted bimonthly (six times a year) along with an annual site-by-site survey utilizing OGI.

First, it is unclear EPA's justification for this threshold and frequency as comparable OGI surveys in yielding emission reductions. Many of these technology companies are able to produce data that demonstrates the effectiveness of their technologies even at higher thresholds and/or less frequent surveys than those suggested in the Initial Methane Notice. In these cases, a bimonthly requirement with an annual OGI would be much more stringent than, rather than comparable to, the corresponding proposal for a quarterly LDAR requirement utilizing OGI. AXPC believes a frequency of three or four times a year is a more comparable to quarterly OGI surveys, based on even conservative modeling estimates.

In addition, a bimonthly frequency for something like flyover screening technologies, creates operational feasibility challenges to execute when also considering the associated timelines for data processing, quality assurance/quality control (QA/QC) analysis, and on-the-ground follow-up and repair. Depending on the number of sites surveyed, flyovers generally take seven-to-ten days depending on the weather, and then often another ten days before the data is received. Operators must then analyze the information provided before they can send out teams to make repairs. Under EPA's Initial Methane Notice, companies would only have a few days for repairing leaks across an entire survey area, which is not practically feasible and significantly shorter than the timeframe provided for walk-around OGI surveys. On a bimonthly cadence, realistically, operators would still be working to perform repairs when it comes time to do the next flyover, creating material operational inefficiencies and shrinking the emission reduction per survey with the overlap.

Cost must also be taken into consideration in a new source performance standard (NSPS), and a 111(d) existing source rule. The cost of a six-times-per-year aerial survey plus one OGI is greater than the cost of quarterly OGI and will disincentivize the use of alternative technology. Whereas our recommendation of three or four times-a-year frequency would likely yield greater emissions reductions than with four OGI surveys on the ground and operators would realize a cost savings – further incentivizing the use of new technology.

Given the challenges with approving alternative means of emissions limitation (AMEL) under Section 111(h)(3), we strongly support and appreciate EPA's effort to explore other routes that could ease the ability for new technologies to be utilized for compliance. Using transparent and accepted models, alternate technologies can be demonstrated to be as effective as EPA Method 21 and OGI surveys in achieving emission reductions and which we agree should also be considered Best System of Emission Reduction (BSER). However, the Initial Methane Notice restricts the operators' reasonable ability to implement alternate technologies in the field. We do not believe this was EPA's intent; **AXPC recommends EPA instead consider a matrix approach based on a technology's capabilities, such as an annual survey frequency based on a technology's detection threshold.** The minimum detection threshold should be based on modeling (e.g., FEAST, LDAR-Sim, or other) that demonstrates that the alternate technology is expected to achieve the required emission reductions. This framework approach would not need then to specify particular technologies or deployment platforms, rather it could specify the comparable frequency based on a corresponding required minimum sensitivity. The proposed matrix could look like the example below:

Survey Frequency (#/yr)	**Minimum Methane Detection Threshold (kg/hr)**
3	#
4	#
6	#

This framework allows operators flexibility to implement one or more technologies to achieve the emission reduction goals. It would even allow for operational scenarios where a combination of survey methods may be as effective or more effective than a single technology at a given frequency. A matrix like the one above would allow operators to implement any technology based on varying factors, such as geographical region or source density, that meets the minimum detection threshold for any given survey at the required frequency (i.e., a different technology could be used for each of the required surveys so long as it meets the minimum detection threshold). Separate matrices could also be developed based on the requirement to perform an annual OGI or EPA Method 21 survey in addition to the screenings with alternate technologies. A matrix like the one above would allow operators to implement any technology so long as it meets the minimum detection threshold as supported by modeling.

EPA's framework should also support the use of continuous monitoring technologies. While continuous monitoring technologies may not lend themselves specifically to this sample matrix above, EPA should establish simple and effective requirements for the use of continuous monitoring technologies in a similar manner suitable to the parameters for continuous monitoring technologies.

B. 40 CFR Part 60 Appendix K

The oil and natural gas industry has worked diligently with EPA to integrate OGI monitoring into rules and to develop the specifics of the methodology. We support its continued use and the importance of proper training and technique, however **AXPC has significant concerns with the suggested Appendix K requirements for the deployment of OGI technology at upstream production facilities**. As drafted, Appendix K is unnecessarily burdensome, and in some cases unproductive, for utilization in upstream production operations. Many of the suggested requirements appear to be designed for large process-type facilities such as downstream refineries and do not account for the significantly different design, complexity, distribution, and in some cases operation, of upstream production facilities.

The differences, include, but are not limited to:

- Onshore production well sites are significantly smaller and less complex than a downstream facility, which dramatically changes dynamics such as the time required for surveys for example, and there are significantly more of them;
- Additionally, upstream production operations are not steady-state process operations like a refinery, where the process flow is largely constant and consistent. Producers regularly have to adjust for variable conditions that can occur unpredictably from the formation or on the landscape, such as weather that can prevent or disrupt a planned monitoring activity;
- Downstream facilities have people onsite 24-hours a day, whereas upstream production facilities are often unmanned much of the time. Maintenance and inspection activities, such as for an OGI survey, requires someone to drive out to each site, which are often spread over large geographic areas. The protocol must recognize this dynamic to avoid inducing undue burden and unnecessary secondary emissions; and;
- Because upstream facilities are located on the natural landscape, rather than a large sited industrial location, they often have a different set of safety, environmental, or circumstantial issues to account for in the field, such as potential for H2S gas exposure, ecological considerations, or even landowner limitations.

In addition to the need to account for these fundamental differences, AXPC is concerned that resources to meet the suggested requirements of Appendix K at the frequencies as they currently stand in the referencing subparts and in likely permit amendments would not be available for many years and could make OGI impractical and inefficient for emissions reductions.

For example, based on our review and discussions with OGI manufacturers and their senior experts, the unnecessarily prescriptive and excessive training and qualification requirements laid out in Appendix K will dramatically limit the ability to find and retain adequate numbers of "qualified" senior OGI operators. The suggested training and QA/QC requirements are overly burdensome and will not lead to more effective leak detection. Further, the ownership of various requirements, and particularly the recordkeeping requirements, are unclear and unnecessarily onerous.

It would take many years to hire and train enough OGI operators and senior OGI operators to meet the suggested applicability. The currently drafted Appendix K protocol amplifies this problem, by imposing overly burdensome training and QA/QC requirements that significantly reduce the hours a camera operator can spend monitoring and extends the time it takes to qualify or requalify a camera operator. Training requirements associated with the OGI protocol could be reduced in AXPC's view without sacrificing the effectiveness of emission detection efforts.

Additionally, Appendix K requires a second operator (identified as a senior OGI camera operator) to train and oversee the OGI operators, requiring at least an additional operator for every five-to-ten OGI camera operators doing actual monitoring. Imposing additional non-monitoring overhead does not significantly increase leak detection and repair yet increases costs and inefficiencies.

For example, a senior OGI camera operator is defined in Section 3.0 of the currently drafted Appendix K as a "camera operator who has conducted OGI surveys at a minimum of 500 sites over the entirety of their career, including at least 20 sites in the past 12 months, and has completed or developed the classroom camera operator training as defined in Section 10.2.1." Paragraph 10.2.2 requires a senior OGI operator conduct ten surveys while being observed by a trainee, conduct 40 side-by-side surveys with each trainee, observe 50 surveys performed by the trainee and perform a follow-up survey as a final test of a new trainee. Thus, the senior OGI operator is tied up for the duration of 101 surveys per trainee.

Additionally, there are suggested quarterly performance audit requirements, which would require a day of a senior OGI operator's time for each operator being audited. Thus, there will be a huge demand for senior OGI operators, and those operators will be doing training and audits, rather than monitoring for leaks. Even with reasonable reductions in these individual duties that would still assure well-trained OGI camera operators, we believe the demand for senior OGI camera operators will exceed supply for the foreseeable future. Conceptually, our desire is to have our most experienced camera operators monitoring for leaks a significant portion of their time, not spending all their time training or auditing. That can only be accomplished if there is an adequate supply of such senior people.
We therefore recommend that the criteria for the senior OGI operator designation be revised. As we specifically address throughout these comments, we believe the functions planned for this operator category can be performed by any qualified OGI camera operator with a reasonable amount of current field experience and such a change will assure enough qualified people will eventually be available to perform the training and auditing functions suggested for senior OGI operators. Furthermore, the resulting larger pool of senior operators would permit rotating personnel efficiently through monitoring, training, and audit functions. At a minimum, **we suggest a revised definition of senior OGI camera operator, which removes the requirement as to the career experience of the individual and converts the 20-site current experience requirement to 20 hours.**

We are also concerned that Appendix K would frustrate developing approaches to use drones as an additional means to perform OGI monitoring. Combining OGI cameras with drone functionality can be particularly useful and efficient for monitoring dispersed small sources (e.g., in tankfields) and elevated, hard to reach equipment. **We request that the rulemaking (e.g., in the final rule preamble) remove requirements that a camera must be handheld,** such as the limitation in Appendix K, and **instead make it clear that if operating envelope, dwell time and related requirements are met it does not matter how the camera is mounted** (i.e., a single camera may be used with any mounting system including a drone or even be handheld).

AXPC recommends that OGI Protocols for the upstream industry be based on OOOOa requirements, and not Appendix K. AXPC has provided additional technical comments on the draft EPA technical support document (TSD) titled, "Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging[2]" (VOC/GHG OGI TSD) found in Appendix A, that describes in more detail our concerns with specific sections of Appendix K. **Overall, AXPC recommends that OGI Protocols for the upstream industry be based on OOOOa requirements, and not Appendix K.**

C. Fugitive Emissions

EPA's definition of "fugitive emissions" on page 86 FR 63,170 conflicts with the current definition of fugitive emissions used in EPA's New Source Review (NSR) and Title V permitting programs. *See* 40 CFR 70.2 and February 10, 1999, memo from Curran). Therefore, **AXPC recommends that EPA revise the definition to be consistent with the current definitions used by EPA.**

[2] EPA-HQ-OAR-2021-0317-0075.

Within EPA's Initial Methane Notice, the Agency indicates that it would define "fugitive emissions component" as:

> any component that has the potential to emit fugitive emissions of methane and VOC at a well site or compressor station, including valves, connectors, PRDs, open-ended lines, flanges, all covers and closed vent systems, all thief hatches or other openings on a controlled storage vessel, compressors, instruments, meters, natural gas-driven pneumatic controllers or natural gas-driven pumps. However, natural gas discharged from natural gas-driven pneumatic controllers or natural gas-driven pumps are not considered fugitive emissions if the device is operating properly and in accordance with manufacturers specifications. 86 FR 63,170.

On the other hand, 40 CFR 70.2 defines fugitive emissions as "those emissions which could not reasonably pass through a stack, chimney, vent, or other functionally-equivalent opening."

EPA's NSR and Title V regulations do not consider whether a source is operating properly to determine if their emissions are fugitive. Instead, for the new source rule, it should be determining if it could reasonably (or is it technically feasible) to pass through a stack, chimney, vent, or other functionally equivalent opening.

With respect to pneumatic devices, not all pneumatic devices are able to connect piping to route vented gas back into a lower pressure process or to a control device. The figure below shows a vent that can be unscrewed and has standard pipe threads that can be adapted to piping on the left and a pneumatic device that does not have that capability on the right.

AXPC recommends that EPA instead preserve the long-standing and widely accepted definition of fugitive emissions as outlined above and revise the definition in the Initial Methane Notice to be consistent with the current definitions used by EPA.

As supported by the statements above, inclusion of control devices, including flares, with emissions resulting from the device operating in a manner that is not in full compliance with any federal rule, state rule, or permit as a fugitive emission is wholly inappropriate for multiple reasons. Not only does it not meet the long-standing and widely accepted definition of fugitive emissions as outlined above, but there is not a generally accepted methodology to inspecting a control device using current fugitive emission monitoring practices, audio, visual, and olfactory (AVO) and OGI. For AVO, an inspector would only be able to identify with the naked eye if the flare is lit or unlit. The inspector would not be able to identify if the flare is 'not operating in compliance' with a broad myriad of federal, state, and permit requirements. Similarly, an OGI inspection would be able to identify if the flare is lit or unlit, but determination of whether a malfunction is occurring that could indicate it is operating out of compliance is overly subjective. There is no published protocol that outlines how a control device should be observed with an OGI camera and what determines a malfunction. For example, a 95 percent control efficiency is allowed, so theoretically 5 percent of waste stream emissions are allowed to be emitted into the atmosphere. It's not appropriate to think that an OGI inspector will be able to identify that any uncombusted emissions observed are greater than the allowed 5 percent; therefore, demonstrate the control device is not in compliance.

Although AXPC does not believe it is appropriate to classify a malfunction or operational upset as fugitive emissions, if EPA is intent on trying to regulate those conditions in some other manner, AXPC believes it is important to understand malfunctions occur from mechanical equipment, but every malfunction may not be a potential violation of the underlying standards for the source of emissions. There are some circumstances where EPA's requirement to "take corrective action to complete all necessary repairs as soon as practicable and prevent reoccurrence of emissions," could require a complete re-design of a facility. An example EPA includes in the Initial Methane Notice is "unintentional gas carry through," more commonly referred to as stuck dump valves (different than stuck liquid level controllers). The root cause of unintentional gas carry through is typically that debris in a liquid line prevents a valve from closing. Most pressure vessel packages are not designed with a mechanism to catch debris prior to the valve, due to the infrequent occurrences when debris prevents the valve from closing. It is not cost effective in this example to implement a corrective action to *prevent* the emissions, but there are several options available to reduce the emissions (several of which may already be in place and new technologies are being developed and approved such as alternative emissions monitoring). AXPC suggests the following language to better account for these situations:

> In the case of a malfunction or operational upset of a control device or the equipment itself, where emissions are not expected to occur if the equipment is operating in compliance with the standards of the rule, this proposal would require the owner or operator to conduct a root cause analysis to determine why the emissions are present, take corrective action to complete all necessary repairs as soon as practicable and <u>*if reasonably feasible to*</u> prevent reoccurrence of emissions, and report the malfunction or operational upset as a potential violation of the underlying standards for the source of the emissions.

D. Wellhead Only Well Site

EPA needs to revise the Initial Methane Notice's suggested definition of "wellhead only well site," for purposes of applying the fugitive emissions standards, which as represented in the preamble language says, "contains one or more wellheads and no major production and processing equipment." Then the term "major production and processing equipment" refers to "reciprocating or centrifugal compressors, glycol dehydrators, heater/treaters, separators, and storage vessels collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water." **AXPC appreciates EPA recognizing that a wellhead only site should be subject to different fugitive emissions standards, but as written, the definition of major production and processing equipment is too broad and will pull in sites that for all intents and purposes is a wellhead only well site.** For example, a single storage vessel at a wellhead could meet the definition of "major production and processing equipment." Although not routinely producing any sort of liquid, it's common practice to see a single tank, at what is traditionally thought of at a wellhead only site, to ensure that if any liquid is ever recovered at the facility that there is proper storage and handling capacity to manage it.

Similarly, natural gas-driven pneumatic controllers, natural gas-driven pneumatic pumps, and pumpjack engines should not meet the definition of "major production and processing equipment" as each of these pieces of equipment do not function as the primary equipment for production and processing purposes, but instead, commonly serve in supplementary roles for the equipment characteristically associated with "major production and processing equipment." Further, natural gas-driven pneumatic controllers, natural gas-driven pneumatic pumps, and pumpjack engines can all be found in operation with production and processing equipment at both well sites and wellhead only well sites. If they were to be included as "major production and processing equipment" it's possible that no facilities would even qualify as a wellhead only well site. This ancillary equipment should be considered as such because they clearly do not meet the definition of "major production and processing equipment."

The definition should also include the type of production and lack of processing associated with wells that only have a storage tank and no other equipment installed at the same location. The storage vessel in this type of configuration serves as a secondary production collection point. These types of wellheads primarily produce gas and do so directly from the wellhead to the sales line. Liquid production is minimal from these wells, as the wellbore pressures are depleted and require rod lift to artificially produce liquids. There is no separation for production from these wells as the liquids produced are extremely minimal, removing any benefit or need for processing equipment. Because the storage tank is installed only to collect liquids that are inconsistently produced from the well, it cannot be defined as major production equipment, making the wellhead the only significant piece of equipment.

IV. PNEUMATICS

AXPC supports efforts to reduce emissions from pneumatic devices across our sites. In general, AXPC supports the Initial Methane Notice's approach of moving towards non-emitting pneumatics at newly constructed sites, however, we believe some clarification is needed. Such as, we recommend EPA use the term "non-emitting" versus "zero emitting" as the latter would be imprecise. Further, we recommend EPA allow for the use of various technologies in order to achieve "non-emitting" status, including the option of routing to an existing control device if it is feasible to do so. The best path to achieve a "non-emitting" threshold for pneumatic devices will be different for each site based on the specific site design, operation, and circumstance. For example, upstream facilities are often located in remote locations without access to grid power, which may necessitate multiple solutions to achieve a "non-emitting" standard. Similarly, where weather can be a limiting factor, operators may need a different suite of solutions to manage that dynamic. Examples to reduce these emissions include but are not limited to: pneumatic controllers driven by compressed instrument air; electric controllers; mechanical controllers, and routing natural gas controllers to a process, sales line, or combustion device.

AXPC also believes it is important that EPA's rules allow for flexibility in determining the best approach for supplying onsite power as needed for driving non-emitting pneumatics. Developing adequate power supply to remote locations, such as are typical in upstream development, can present significant challenges. As most upstream site locations are leased, not owned, and facilities are temporary (not permanent) it is not always realistically feasible to electrify a location from the grid due to issues outside the operator's control. Similarly, the viability of solar-powered technologies is still being evaluated and has presented reliability challenges to several of our member companies who have piloted their use in the field. For remote sites without power grid access, many sites are supplied by onsite power generation such as through natural gas or even diesel generators. Though the use of these generators would present a tradeoff of criteria pollutants for methane reduction, still for engines of this size those emissions are not significant and already subject to thorough regulation and reporting requirements.

Still, to achieve the large-scale deployment of non-emitting pneumatic devices that the Initial Methane Notice envisions we ask EPA to account for these circumstances where an operator cannot obtain grid power (whether for legal or practical reasons), where there are delays in building grid connections, or where renewables may not be a reliable or feasible option, and allow for the use of natural gas or diesel generators as the most feasible option to achieve a non-emitting control standard. **We also believe it is important that the supplemental proposal specify that that it is not the agency's intent to require operators to run new commercial power lines, certainly in situations where it would be practically, technically, or economically infeasible to do so.**

The flexibility to use different options is important when the non-emitting standard is being applied to newly constructed sites and even more critical for existing sites. There are a variety of different facilities sizes, operational approaches, and location specific circumstances that affect the technical feasibility and cost-effectiveness of converting an existing site over to non-emitting pneumatic devices. In some cases, doing so may require an overhaul of how an asset is being operated or the overall emission control strategy. It will be critical that EPA allow for sufficient time to phase in these standards including for technical feasibility assessments, sourcing and purchasing necessary equipment and materials, planning and potential design changes or modifications of emission control strategies, in addition to the eventual time to execute the retrofit. **At a minimum, a three-year phase-in from finalized rules and guidelines should be allowed for implementing the standard at existing locations**. And for both new and existing source requirements, EPA should grant additional implementation time in light of the global supply chain challenges that are already challenging an operator's ability to secure components like pneumatic devices, and which will be exacerbated by the nationwide demand increase as a result of this rule.

Further, **AXPC believes it is warranted for EPA to reconsider the Initial Methane Notice's suggested definition of affected facilities as it relates to pneumatic controllers.** The approach in the Initial Methane Notice would dramatically change the emission control strategy for these facilities such that the basis for and historic definition of a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than six standard cubic feet per hour (i.e., high-bleed controller) no longer makes sense, and in particular as it relates to delineating what constitutes a modification.

AXPC would instead recommend, as it relates to pneumatic controllers, that EPA define an affected facility as the onsite collective rather than an individual controller. Such as the following:

> Pneumatic controller affected facility: the collection of natural gas driven pneumatic controllers that vent to the atmosphere located at a well site, centralized production facility, or compressor station.

This approach would be more consistent with EPA's cost analysis which assumed the control options would occur at the site level and not just for an individual controller.

Further, **where an existing site has only one or a few pneumatic devices, and no grid access or ability to route to an onsite control device, retrofitting would not be realistically feasible. AXPC believes requirements to retrofit existing to non-emitting be based on a technical feasibility assessment** that determines that:

1. There are more than five controllers at the well site, central production facility, or compressor station; and
2. The site has access to sufficient grid power onsite, and/or a feasible route from specific controllers to an existing combustion device.

In circumstances found not feasible, the use of continuous low-bleed and intermittent natural gas controllers should be allowed and covered in an operator's existing LDAR monitoring program to monitor proper functioning, similar to EPA's suggested requirements for Alaska.

Similarly, should a single pneumatic controller break and need replacing or repair, that activity alone should not trigger as a modification subjecting the site to new source requirements. Rather modifications should be based on material site level changes and not per controller. Using a single replacement as a triggering event could result in a perverse incentive to delay maintenance or sub-optimally repair a controller resulting in more emissions.

AXPC also believes it is imperative that EPA recognize circumstances where exceptions are entirely warranted. For example, an operation may require use of temporary or portable equipment for a short period of time (i.e., less than 180 days) where there they may not be the ability to connect to the grid or route to an onsite control device. Other circumstances can include when an existing site may have sizing constraints, other permit limitations, and/or safety concerns that inhibit a non-emitting retrofit.

Emergency shutdown devices (ESDs) should also remain exempt from the pneumatic controller requirements contained in the Initial Methane Notice. For example, even where a limited application of mechanical and solar actuated controllers could be used in individual controller circumstances, site-wide control strategy, especially around ESD's would not be feasible. An ESD is designed to minimize consequences of emergency situations, and will only emit in certain isolated circumstances, such as if a well must be shut in. A large, instantaneous motive force is required to close an emergency shutdown device, which may not be deliverable with sufficient speed by an electric controller or subject to unacceptable reliability risk if reliant on an instrument air compressor. Furthermore, if power is lost, these devices must still be able to be function. Because ESDs are rarely activated, their emissions impact is minimal, but their functional need is necessary and critical to safe operations. We recommend that EPA's rule allow for these limited but real-world situations.

It is unclear whether EPA recognizes OOOOa excluded pneumatic diaphragm pumps in operation less than 90 days per calendar year. OOOOb uses words like "all" pneumatic diaphragm pumps and "also includes piston pumps." It is important that EPA recognize that many pumps operate on a seasonal or very low frequency. Examples include pneumatic diaphragm pumps used to remove rainwater from secondary containments and piston pumps used to inject methanol to prevent freezing during winter months. In both scenarios, the feasibility analysis may determine it is infeasible, which AXPC supports inclusion of the infeasibility documentation process. However, the cost to route the gas to a control or process where it is feasible may not be warranted. In some situations, the pump could be a significant distance from the available control device or process requiring expensive trenching to bury lines for very few emissions reductions. The infrequent operation and emissions associated with the infrequent operation will likely affect the cost-benefit analysis in the Initial Methane Notice's suggested requirement to control all pneumatic diaphragm and piston pumps in the Production Segment and the Transmission and Storage Segments.

V. Reciprocating Compressors

AXPC recommends that instead of considering the annual review based on a calendar year (i.e., 365 days) that EPA consider with respect to operation of an annual number of hours (i.e., operation of 8,760 hours). *First*, it is not readily feasible for operators to measure the leak rate to determine if the rate has exceeded the 2 standard cubic feet per minute (scfm), operators will likely have to default to replacing the packing annually in order to comply with this requirement. As EPA's intent is to have a reasonable amount of time pass before review, it should be based on actual use instead of potential use.

In upstream operations, production gas lift compressors do not see the pressures and continuous service as midstream station compressors. Basing the requirement on operational hours would make sure that operators are not having the burden and expense of going through the reviews or replacements even when a compressor has not been operating for multiple months. Similarly, it could avoid potential confusion that could otherwise be created by recordkeeping and reporting requirements, such as for situations like when a leak occurs on day 364. There should be an exemption for small reciprocating compressors less than 100 horsepower (i.e., vapor recovery units) that experience has shown do not exhibit rod packing leaks even without replacement. There are no benefits that come from requiring replacement for these smaller units while the cost would be significant.

Additionally, the universe of compressors subject to regulation will greatly increase since the OOOOa and OOOOc timeframes overlap resulting in previously excluded well site compressors that were exempt under OOOOa would eventually be pulled into OOOOc based on the Initial Methane Notice. Replacing the rod packing every year for every compressor regardless of size and hours used could be unreasonably burdensome.

VI. Well Liquids Unloading Operations

In general, AXPC supports the development of a work practice standard using Best Management Practices (BMPs) for liquids unloading events utilizing methods that vent, provided the standard allows for needed operational flexibility. However, we believe the Initial Methane Notice needs additional clarification to more clearly define liquids unloading and better align with the statute, existing state programs, and EPA's Greenhouse Gas Reporting Program (GHGRP).

A. Liquids unloading operations do not represent a "Modification"

Liquids unloading is a routine aspect of operating a well. It does not represent a physical or operational change to that well and does not necessarily result in an increase of the affected facility's potential to emit. Almost all wells experience liquids unloading at some point in the life of the well, some even as a stage of primary production. There are a number of methods an operator may use based on the engineering needs of the well, and an operator may even need to adjust the method being used over the course of the same day. However, not all methods for liquids unloading involve the venting of emissions or cause the affected facility to increase its potential to emit. For these reasons, AXPC is concerned that adopting the approach in the Initial Methane Notice—that a liquids unloading event *per se* represents a modification of the affected facility—is not in keeping with the statue. The CAA provides that a source undergoes "modification" when it is subject to "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." Section 111(a)(4), 42 U.S.C. § 7411(a)(4). While **we support the use of BMPs as a work practice standard to minimize the methane emissions associated with vented liquids unloading events with some clarifications, an approach under which each unloading event constitutes a modification is in conflict with the statute**, because, as explained above, liquids unloading is not, *per se*, either a physical change to the source or a change in its method of operation, nor does it necessarily increase the source's emissions.

B. Support for Option Two with additional clarification

As explained above, AXPC's position is that the approach in the Initial Methane Notice, under which EPA would deem liquids unloading to categorically constitute modification, is not within its authority under the statute. Separate and apart from that issue, of the options presented rather than Option 1, which defines the affected facility as *every* well that undergoes liquids unloading, **we generally would support EPA's Option 2. But, we request EPA clarify in Option 2 that its liquids unloading requirements will apply specifically to gas wells utilizing venting liquids unloading techniques.** This approach is consistent with EPA emission reporting requirements under the Greenhouse Gas Reporting Program at 40 CFR Part 98, where Calculation Methodology 1 states *". . . where gas wells are vented to the atmosphere to expel liquids accumulated in the tubing . . ."* **Additionally, we recommend EPA utilize the existing required reporting for liquids unloading under Subpart W, and that EPA not impose additional reporting requirements[3,4] and generally recommend protecting workers by eliminating or reducing exposures to hazardous atmospheres**. As previously noted, EPA's GHGRP is adequate for liquids unloading reporting and quantification.

C. Flexibility for liquids unloading operations

AXPC's view is that it is crucial to allow flexibility for liquids unloading operations, and we appreciate that EPA acknowledges this.

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[3] For reporting of liquids unloading events that result in vented emissions, the EPA currently requires reporting of liquids unloading vented emissions under GHGRP 40 CFR Part 98 Subpart W using Equations W-7, W-8, or W-9 of §98.233(f).

[4] Health and Safety Risks for Workers Involved in Manual. Tank Gauging and Sampling at Oil and Gas Extraction Sites. https://www.osha.gov/sites/default/files/publications/OSHA3843.pdf

We agree with EPA's observation, at 86 Fed. Reg. 63,211, that "Selecting a particular method to meet a particular well's unloading needs must be based on a production engineering decision that is designed to remove the barriers to production."

We also agree with EPA's observation, at 86 Fed. Reg. 63,213, that "there may be safety and technical reasons why venting to the atmosphere is necessary to unload liquids. In addition, it is possible that a well production engineer has already explored non-venting options and determined that there was no feasible option due to its specific characteristics and conditions."

We furthermore agree with the EPA's observation, at 86 Fed. Reg. 63,180, "that that there may be reasons that a non-venting method is infeasible for a particular well, and the proposed rule would allow for the use of BMPs to reduce the emissions to the maximum extent possible for such cases."

D. Issues with focus on "design" instead of venting events

AXPC's position is that EPA should focus on liquid unloading events that result in venting, rather than the "design" of the liquids unloading method.

EPA's option discussed in the Initial Methane Notice to use the wells' designed unloading methods and whether the methods are designed to vent or not as the basis for determining an affected facility would create significant ambiguity. *See, e.g.*, 86 Fed. Reg. at 63,211/1 ("Under the second option, the affected facility would be defined as every well that undergoes liquids unloading using a method that is not *designed* to totally eliminate venting (i.e., that results in emissions to the atmosphere)"). (Emphasis added). The design of a well's liquids unloading strategy often can give rise to multiple possible outcomes depending on various factors that can change daily, e.g., operating temperatures and pressures, reservoir behavior, gathering and compression systems, offset well effects, etc. Any attempt to define affected facilities based on whether a well is "designed" to vent during unloading or not is problematic, because both design possibilities may and often do exist concurrently at a given well.

All wells will eventually require liquids unloading at multiple points over the course of their operations, although one cannot necessarily predict when or how many times over the life of the well, nor will it be the same for every well. Similarly, the methods used to unload liquids throughout the life of the well will change depending on the conditions of the well. A method that was, at one point, successful in routing the well stream to a separator with no venting may eventually cease to successfully unload liquids due to changes in well conditions. The ostensible "design" method is therefore not an accurate predictor of whether unloading activities at a given well will or will not result in unloading during a given point in the well's life, and so framing the rule in terms of a well's "design" in this regard is not relevant and will only lead to confusion. EPA should only require reporting of the *events* that result in venting from a given well, without labeling a well as "designed" to unload without venting.

Any extension of this requirement to existing sources would be particularly inappropriate in light of the clear focus of 111(d)'s text, structure, and purpose on allowing states to take into account the particular characteristics of a source over the course of its operations ("remaining useful life" and "other factors"). However, even solely in terms of the Administrator's new-source authority, a standard would not be "adequately demonstrated" and/or "achievable" if it did not take into account the manner in which sources actually operate in the course of production. Because, as explained above, and contrary to EPA's apparent assumption in the Initial Methane Notice that wells and their unloading procedures are not "designed" for only one type of unloading procedure, EPA should in the supplemental proposal propose a standard that requires reporting of unloading *events* that actually result in venting—not one, as in the Initial Methane Notice, that bases applicability around a source's and/or its unloading events' "design."

E. Best Management Practices (BMPs)

Separate and apart from AXPC's concerns, recommendations, and observations expressed above, to the extent that EPA adopts requirements for liquids unloading, ***<u>we support criteria for BMPs tha</u>***t:

- **Require the reporting of vented emissions as per "Gas Well Venting for Liquids Unloading according to Petroleum and Natural Gas Systems source category of the GHGRP 40 CFR Part 98 Subpart W using Equations W-7, W-8, or W-9 of §98.233(f)."**
- **Require an operator at the wellsite or in close proximity, unless automation equipment, remote sensors, and/or other surveillance technologies are used.**
- **Require the operator to report when the BMPs have not been followed.**
- **Allow for the use of flaring as a control option.**
- **Allow for routing emission to a sales line or back to a control process if possible.**
- **For states where a BMP governing liquids unloading event is required under the states' NSR program, such BMPs should be deemed sufficient and satisfy the requirements of NSPS.**

<u>We object to criteria for BMPs that would require:</u>

- Technical justification for the unloading methodologies employed.

As previously noted, we agree with EPA's observation, at 86 Fed. Reg. 63,211, that "Selecting a particular method to meet a particular well's unloading needs must be based on a production engineering decision that is designed to remove the barriers to production." Such a requirement would merely be a record keeping and reporting burden, with no added value or direct emission reduction benefit.

- Process flow explanation and/or diagrams of unloading activities.

Many well sites, especially sites with multiple wells, have a complex surface piping system for equipping the site that could result in any number of liquids unloading activities. Additionally, the process footprint during a liquids unloading event can change throughout the life of the well depending on well conditions. Describing clearly where a well stream is directed via a process flow diagram and explanation is often a complex and burdensome task that would ultimately not yield value in this context. To reduce recordkeeping burden, EPA should consider operating parameters and associated emissions already reported to EPA under Subpart W reporting requirements.

- Direct measurement of vented emissions.

The direct measurement of vented emissions is not always possible and runs a serious risk of exposing personnel to hazardous atmospheres. NIOSH-OSHA have issued a Hazard Alert associated with working around open top tanks,[5] and generally recommend protecting workers by eliminating

[5] Health and Safety Risks for Workers Involved in Manual. Tank Gauging and Sampling at Oil and Gas Extraction Sites. https://www.osha.gov/sites/default/files/publications/OSHA3843.pdf

or reducing exposures to hazardous atmospheres. As previously noted, EPA's GHGRP is adequate for liquids unloading reporting and quantification.

F. Flaring should be allowed as a control option.

Though there are scenarios that would not support a flare as a control option for liquids unloading venting, there are also opportunities to use flares in many cases and flaring in those situations provides a significant opportunity for methane emission reductions. AXPC has provided additional technical comments in Appendix B that describes in more detail our views on the use of flares as a control option and that an unloading event controlled with a flare would be considered as non-venting.

VII. STORAGE VESSELS

In general, AXPC supports EPA's approach to regulate storage vessels as a single storage vessel or a tank battery affected facility and does not take issue on the 6 tpy VOC threshold for completely new sites and a 20 tpy threshold for existing sites. However, AXPC does have concerns with the definition of tank battery as overly complex and it would create confusion potentially leading to unintended consequences. **For a clearer delineation, we would recommend that the definition of tank battery be based on tanks that are manifolded by liquid line as per the modified definition offered below. This definition would avoid confusion around applicability and align with existing state programs.**

> The EPA proposes to define a tank battery as a group of storage vessels that ~~are physically adjacent and that receive fluids from the same source (e.g., well, process unit, compressor station, or set of wells, process units, or compressor stations) or which~~ are manifolded together for liquid ~~or vapor~~ transfer.

Similarly, AXPC believes the definition for what constitutes a modification of a tank battery is inconsistent with the definition of modification within the Clean Air Act Section 111 (40 CFR § 60.14) which is generally defined as "any physical or operational change to an existing facility which results in an increase in the emission rate to the atmosphere of any pollutant to which a standard applies." For example, EPA in the Initial Methane Notice suggests that a single storage vessel or a tank battery is modified when it "receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput (from activities such as refracturing a well or adding a new well that sends these liquids to the tank battery)." However, in this example, the storage vessel or tank battery is neither physically changed nor operationally changed as the change occurred at a different affected facility. Further, the example does not speak to a demonstration that the additional throughput resulted in an increase in the emission rate of the storage tank or tank battery. Practically speaking, operators would not be able to compliantly send additional throughput to a vessel or battery that would cause the facility to exceed its permitted emissions. It is also important to note there will be circumstances that an operator may have need to replace a storage vessel, which should not trigger modification unless it increases the potential to emit at the facility. **AXPC recommends that in this section EPA adhere to the statutory definition for modification as it relates to a single storage vessel or a tank battery.**

> The EPA is proposing that a single storage vessel or tank battery is modified *when physical or operational changes are made to the single storage vessel or tank battery that result in an increase in the potential methane or VOC emissions.* (Emphasis added).

AXPC also recommends that EPA preserve its alternate control standard in OOOOa that allows for a sustained uncontrolled VOC emission rate of less than 4 tpy as an alternative emission limit to the 95 percent control requirement under specified circumstances. Over time, due to inevitable production declines, there may be an inflection point after which an operator would have to supplementally feed the flare in order to get it to operate. This would result in the emissions from operating control device exceeding the emissions that would otherwise be vented to atmosphere. This 4 tpy alternative standard provides the pathway to avoid those unnecessary excess emissions. Similarly, for OOOOb and NSPS OOOOc, AXPC recommends that EPA consider extending a technical infeasibility exemption if a control device would require supplemental fuel.

AXPC also recommends that EPA continue its allowance of state program alternatives for the regulation of storage vessels or tank batteries to reduce what would otherwise be duplicative control, recordkeeping and reporting requirements. This state program alternative has been entirely successful at achieving EPA's desired outcome for ensuring emissions from these facilities are controlled.

VIII. Oil Wells with Associated Gas

AXPC supports non-venting except for when there is technical infeasibility, safety concerns or other similar issues. However, it is also important to understand that there is a limitation on non-pipeline solutions for associated gas. There are some technological solutions but there are certain circumstances when even the most advanced technological solutions do not work. Also, the oil and natural gas operator does not necessarily have the rights to surface property that would be necessary to implement a pipeline or non-pipeline solution – this is not something that operators have the power to do, nor does EPA have the authority to provide them with this power. Thus, AXPC wants to ensure that EPA understands that "access to a sales line" does not equate to availability.

Also, it is unclear what EPA means when they say "continuous" when it comes to a 95 percent destruction. While we do not have regulatory text to directly comment on, we believe that EPA means that it is a 95 percent threshold based on an average over at least 24 hours. We also recommend that there be exemptions for when vent gas rates are insufficient to support continuous flare operation. In those situations, supplemental flare fuel gas would be required to support flare operation resulting in an emission profile exceeding that resulting from the minimal existing vent gas. This situation becomes more common as wells age and overall production rates decline.

AXPC also respectfully disagrees with EPA's assumption that since there are no NSPS that regulate associated gas venting and flaring, that one is therefore needed. There are many emission sources not covered under a NSPS. Emissions from associated gas venting and flaring are regulated under Federal and State New Source Review programs. Further, state and federal regulators charged with oversight of the production of oil and natural gas in their jurisdictions have the primary responsibility over regulating gas flaring and venting as part of their overall obligation. Also, today it is uncommon for associated gas to be vented under normal circumstances for safety reasons, and many state regulations, like North Dakota, prohibit the venting of natural gas and have gas capture regulations that already limit the gas that can be flared without impacting the economics of the industry.

The ratio of associated gas to barrels of oil produced (gas to oil ratio or GOR) can vary significantly from field to field, from no associated gas to thousands of cubic feet of gas per barrel. It can also be intermittent.

Operating a flare in compliance with 40 CFR 60.18 does not demonstrate that the flare is constantly achieving the required 95 percent Destruction Rate Efficient (DRE). There have been studies that show that oil and gas flares can achieve an average DRE in excess of 95 percent (e.g., Steffes).[6] Extreme weather condition can temporarily impact a flares DRE, however that annual average DRE will be equal to or greater than 95 percent.

On oil wells that produce little or intermittent associated gas, a flare or combustor cannot operate efficiently or in compliance with 40 CFR 60.18 without additional gas being supplemented (propane from a propane tank) to provide fuel gas for the pilot and sweep gas. For these situations, it is common to install a pit flare with an auto ignitor that will ignite the gas when present. These are not as efficient as an engineered flare that complies with 40 CFR 60.18, but it is the best technology for the situation.

IX. State Plans

AXPC appreciates that EPA has stated its intention to supplement the Initial Methane Notice with a supplemental proposal, to contain, among other things, proposed regulatory text for new subpart OOOOc, which is an "emissions guideline" governing the states' development of existing-source plans. AXPC looks forward to reviewing the proposed regulatory text for subpart OOOOc when it is made available, as well as to any additional information and solicitation of comment that EPA includes in the supplemental proposal.

With respect to the state planning process for existing sources pursuant to the new subparts OOOOc and Clean Air Act Section 111(d), 42 U.S.C. § 7411(d), AXPC urges EPA, in its forthcoming supplemental proposal and in the eventual final rule, to provide the broadest possible degree of flexibility to states in developing their plans that establish standards of performance for existing sources. This is in keeping with the text and structure of Section 111, as well as with the common-sense observation that it is easier for regulated companies to plan and execute design and operational changes for new and modified sources than for existing sources.

Section 111(d) provides that it is the *states* who in their plans establish standards of performance for existing sources, subject to EPA review and approval. And subsection (d) explicitly requires EPA to allow states to "take into consideration, among other factors, the remaining useful life of the existing source" for which the state plans establish standards of performance. The existing-source program is, therefore, a "cooperative federalism" program under which Congress intended that states would have considerable flexibility in establishing standards of performance for existing sources. EPA's supplemental proposal and final rule should reflect this by providing states with latitude in the standards they establish for their existing sources, to include: allowing states to establish less stringent or no standards on sources with a short remaining useful life; allowing for states to submit any existing regulatory programs they may already have adopted with no or little alteration where those programs would appropriately serve the text and purposes of the Clean Air Act and comport with the framework established in this federal rulemaking; and allowing states to provide their existing sources with broad latitude in choice of monitoring and other compliance measures.

[6] Combustion Efficiency Performance Testing of Pressure Assisted Flares Utilizing Passive FTIR, Sage Environmental Consulting for Steffes Corp. (Testing Conducted Sept. 2015, Report Apr. 2016).

As regards the time following finalization of new subpart OOOOc that states will have to formulate their state plans and submit them to EPA, AXPC appreciates that EPA is committed to proposing this timeline in its forthcoming supplemental proposal and soliciting comment on this forthcoming proposed timeline. *See* 86 Fed. Reg. at 63,255/3. Generally speaking, AXPC's view is that it is vital for states to be given an appropriate amount of time to develop and submit their plans. AXPC cannot take a definitive position as to how much time is required for state plan formulation and submittal until the supplemental proposal is published, to include proposed regulatory text for new subpart OOOOc.

AXPC can, however, offer these observations: The default period of nine months, as provided for in the 1975 general implementing regulations for 111(d), is facially inappropriate here. The state plan process for this existing-source rule will contain more sources than any such previous rule—potentially several orders of magnitude more—and existing facilities in this sector are likely more subject to site-specific variations than any category of existing sources that EPA has previously regulated under 111(d). An appropriate timeline here would certainly be measured in years, not months.

X. ADDITIONAL EMISSION SOURCES

As a general matter, AXPC has concerns about EPA's broad suggestion that it may regulate additional emissions sources beyond those explicitly discussed in the Initial Methane Notice. Without further information from EPA, to include both full analysis in the supplemental proposal and proposed regulatory text, AXPC cannot provide informed comment on this topic.

A. Abandoned and unplugged wells

In the Initial Methane Notice, EPA solicits comments on the potential for addressing issues with emissions from "abandoned, or non-producing oil and natural gas wells that are not plugged or are plugged ineffectively." 86 Fed. Reg. at 63240. The language suggests that EPA is considering requirements for operators to have to submit plans for plug and abandonment along with associated financial assurance for decommissioning obligations. **State oil and gas agencies and federal land management agencies (i.e., Bureau of Land Management (BLM)) have the authority to regulate the management and decommissioning of oil and gas wells.** Operators are already subject to regulatory requirements for posting financial assurances to cover decommissioning costs and clean up, submittal of plans and technical procedures for temporarily abandoning or permanently decommissioning a well. In addition to this potential for creating redundant regulations, EPA has no authority under the Clean Air Act to impose such a financial assurance requirement. **We believe issues related to well closure are more appropriately addressed by the states and federal land management agencies like the BLM.**

Additionally, there appears to be a lot of confusion over the terminology that is leading to misconceptions and misunderstandings. For example, "abandonment" refers to the proper process of removing a well or pipe from service. Wells can be permanently plugged and abandoned, or temporarily abandoned if re-entry is anticipated, however both cases in general speak to leaving the well in a regulatorily compliant, protective state. Whereas EPA's definition of "abandoned" includes all wells that are no longer in production; however, these wells may or may not be plugged. These terms are also often conflated with references to "orphan" wells or "idled" wells. These sort of inconsistencies in terminology have led to incorrect counts and estimations as they relate to concerns on the landscape. Similarly, there have not been many studies looking at emissions from abandoned and unplugged wells, or from orphan wells, and what studies there are do not geographically represent the entire US and/or were biased by the inclusion of noticeable outliers. For these reasons AXPC believes that emissions from abandoned wells are not as great as EPA suggests. This type of information is part of an ongoing dialogue with EPA's Climate Change Division concerning potential updates to the US Greenhouse Gas Inventory (GHGI).

It is also important to note that state oil and gas regulators and other parts of the US government are already considering and addressing the issues that EPA has raised related to the proper management of idle well inventories, providing for proper well abandonment, as well as addressing the existing inventory of orphan wells. For example, the Interstate Oil and Gas Compact Commission (IOGCC) is a multi-state government agency that promotes the conservation and efficient recovery of domestic oil and natural gas resources while protecting health, safety, and the environment. The IOGCC has been studying this issue for 30 years and supporting states and provinces in their efforts to continually improve their idle and orphan well programs and sharing effective tools and strategies. As recent as December 2021,[7] IOGCC issued an updated report entitled "Idle and Orphan Oil And Gas Wells: State and Provincial Regulatory Strategies 2021." In this report, IOGCC found that less than 6 percent of all drilled and not plugged (includes all operational wells) are considered orphaned by the states. Of these orphaned wells, the operator is known for 78 percent of the wells. Estimates for the number of undocumented wells, legacy wells typically drilled prior to the establishment of regulatory programs, are much higher. However, the existence of these undocumented wells should not be conflated with the modern definition of orphan wells, which are managed through various techniques such as bonding and state/operator funded orphan well plugging programs. **IOGCC's work and recent report should be relied upon for establishing consistent terminology, improving counts and estimations, and reviewed carefully before considering additional regulations.**

Additionally, in its passage of the Infrastructure and Investment Jobs Act of 2021 (IIJA) Congress provided nearly $4.3 billion in funding to address orphaned wells on state, federal, and tribal lands, plus additional funds for states to update associated regulatory programs, and for related research, development, implementation and other support.[8] **The issues that EPA is concerned with are actively being tackled by regulators with primary authority over these operational activities and with significant federal funding to able to implement and address challenges.** It is AXPC's position that EPA should not create duplicative and unnecessary regulations, which may ultimately conflict with specific rules promulgated by the states and BLM to address orphaned, idle, and abandoned wells.

B. Pipeline "Pigging" Operations

The US Pipeline and Hazardous Materials Safety Administration (PHMSA) is already regulating the midstream pipeline system and recently passed the PHMSA reauthorization law that directed PHMSA to reduce methane emission in the pipeline. To the extent that EPA believes that it is may be necessary to regulate pipeline pigging operations, AXPC recommends that EPA allow PHMSA to first develop regulations and determine whether it would be appropriate for EPA to regulate on top of PHMSA. Additionally, similar to upstream operations, it is important that any regulation of these activities provide for operational flexibility in technology and approach.

[7] https://iogcc.ok.gov/sites/g/files/gmc836/f/iogcc_idle_and_orphan_wells_2021_final_web.pdf
[8] REGROW Act Infrastructure and Investment Jobs Act of 2021, H.R. 3684, 117th Congress (2021)

C. Tank Truck Loading Operations

Truck loadout controls are added to existing facilities by the addition of new vent lines to an existing combustor and/or installation and operation of an additional or larger capacity combustor at the applicable facility. This analysis may require substantial design evaluation work to ensure that the use of existing control devices is feasible, and if not, to design and install a new combustor control device. There are significant concerns with redesign requirements for older facilities, training of haulers, availability of space for new required combustor/flares, introduction of excess oxygen to the system if routed to tanks (generally because flare lines may be too small to accommodate the instantaneous volume from a truck load). Further, these requirements will have disproportional impact on low-liquid-producing sites with infrequent loading/unloading events. Additional practical, technical and safety considerations EPA should consider as it reviews tank truck loading vapors at new and existing locations:

- Some older facilities do not have the pad size to safely locate an additional combustor dedicated to loadout controls (if needed). Changes to the pad size require state agency and landowner approval, which may not be obtainable. Additionally, local governments and landowners may further prohibit operators expanding the footprint of a facility.
- If truck loadout vapors are routed through the storage tanks onsite prior to combustion, a new design analysis may be needed, which may generate costly modifications to low-producing sites (i.e., adding additional combustion control, larger combustors, change pipe sizing, etc.) in order to properly design the facility.
- Loadout truck drivers, who may not be familiar with truck loadout air emission equipment being at these older, low-production facilities will need additional training in order to safely use the new equipment. Many times, the trucking company is a separate entity that may change over time from the producer.
- Truck loadout controls may introduce excess oxygen in the system requiring the installation of an independent vapor control system.
- Older vintage buried and semi-buried tanks are not designed to work with truck loadout equipment.
- The introduction of an oxygen rich vapor stream into atmospheric tanks that have minimal headspace. A higher oxygen percentage in the vapor mixture increases the risk of the vapor igniting and creating optimal conditions for a fire or explosion.
- Lower producing facilities may only necessitate infrequent truck loadings based on production decline. EPA must evaluate the cost effectiveness of a specific, reasonable threshold of crude oil/condensate prior to requiring any controls.

D. Improving performance and minimizing malfunctions on flaring

EPA is seeking comment on the appropriateness of applying standards from The Petroleum Refinery Sector Standards, 40 CFR part 63, subpart CC, amended in 2015 (80 FR 75178) for the oil and gas production, gathering and boosting, gas processing, or transmission and storage segments.
The refining sector is vastly different than oil and gas well sites, centralized production facilities, and compressor stations. And unlike most industrial sectors where operating conditions are defined in the engineering stage, the oil and natural gas production sector does not operate at steady state conditions. Equipment design must be tailored to the conditions and fluid compositions supplied by the reservoir.

XI. STAKEHOLDERS AND ENVIRONMENTAL JUSTICE CONSIDERATIONS

AXPC believes that environmental justice (EJ) considerations are important. Our industry is committed to the health and safety of the communities in which we operate, and we work to recruit and elevate diverse talent within our workforce.

United States upstream onshore oil and natural gas supports over 3.2 million jobs – including jobs that pay for health care, good nutrition, livable homes, and more. Our industry is essential to supporting a modern standard of living by supporting communities' access to affordable and reliable energy, and we are committed to working with local communities and policymakers to promote these principles across the energy sector.

Thanks to the use of clean natural gas, carbon dioxide emissions have fallen and continue to fall, and emissions from energy use across the economy are at their lowest level in over 25 years. Natural gas use also reduces other emissions like nitrogen oxide and sulfur dioxide, which is important to improving health.

However, while we support the public being able to participate in development of their communities and believe that they should be provided relevant information on what is going on in their communities, we have significant concerns related to what has been generally called "citizen science" – where members of the public are deputized to act as if they are employees of EPA.

It is difficult for AXPC to comment on a mere concept without something more fleshed out and AXPC will provide additional information if and when EPA proposes regulatory text. EPA seeks comment on how to allow for members of the public to use technology to search for super-emitters, but also potentially any types of emissions. *See* 86 Fed. Reg. 63,177. EPA and industry professionals are trained in how to operate, inspect, and monitor oil and natural gas sites without causing danger to themselves or others.

It is unclear to AXPC why these requirements are being considered in the first place. This provision appears to be duplicative of EPA's current system which allows members of the public to submit potential environmental violations.[9] EPA does not cite any information that this system is lacking or not capable of meeting the purpose for which it was established. To the extent that members of the public believe that there are not enough resources being allocated to processing allegations of environmental violations, AXPC recommends that additional resources be provided to support that issue before considering deputizing members of the general public.

***First*, there are potential safety concerns associated with members of the public accessing sites without proper notice, personal protection equipment (PPE), and training.** For example some sites can contain hydrogen sulfide (H_2S), a gas that could result in series health issues for members of the public without proper protection.

***Second*, well sites are located on private property and providing this authority could encourage members of the public to trespass onto private property and to avoid safety signs and considerations.** This could result in members of the public hurting themselves or damaging equipment that could result in putting workers in danger. There is also the question of who would be liable for the safety for the members of the public who illegally trespass on the property or for any damage that they may cause.

[9] https://echo.epa.gov/report-environmental-violations

***Third*, other members of the public may be confused or misled by claims of significant unauthorized emissions from well sites by citizens.** As members of the public are not aware of permitted activities or where exactly a source of emissions may stem from, they could unintentionally raise alarm to other members of the public unnecessarily.

***Fourth*, as citizens are not necessarily aware of activities that are permitted or all other potential sources of emissions around the wellsite, there is a high likelihood that this will result in EPA and companies having to chase ghost emissions** – i.e., those emissions that are not violations of any permit as they are either permitted activities or not from the wellsite – thus preventing EPA from enforcing actual environmental violations and causing unnecessary burden and harm on companies.

***Fifth*, if information is gathered from members of the public, there is no clear chain of custody on the information to ensure that it is valid and has not been modified.** As this information may be used in enforcement proceedings that could result in significant fines, it is unclear how EPA and the owners of the site can ensure that the information is valid.

***Sixth*, while AXPC has raised concerns with the requirements around Appendix K above, if EPA wishes to move forward with this action, members of the public should be held to the same training and accuracy requirements as operators**, as it does not make sense that EPA should not require the same standards for citizen inspections as it does for industry compliance.

***Finally*, AXPC is generally concerned about the location of such a significant potential policy change. This type of action has broad implications to all other sectors regulated under the Clean Air Act, as well as potentially to other environmental laws under EPA's purview.** Due to the broad implications and potential applications, AXPC recommends that if EPA believes that this is appropriate to move forward with, that EPA do this through a different rulemaking activity such that all members of the public, included all other potentially regulated industries, are able to comment and consider the potential impacts of this action.

APPENDIX A – SPECIFIC COMMENTS ON EPA DRAFT DOCUMENT TITLED *PROTOCOL FOR USING OPTICAL GAS IMAGING TO DETECT VOLATILE ORGANIC COMPOUND AND GREENHOUSE GAS LEAKS*

A. General Terminology

The OGI camera addressed by Appendix K is identified as a "hand-held, field portable infrared camera" throughout the Initial Methane Notice. Field portable cameras that can be hand-held are sometimes mounted on tripods (as indicated in the draft definition of Camera Configuration and elsewhere in the Initial Methane Notice) or mounted on a drone or are set down on a surface or mounted on a harness worn by the operator – and those variants could be interpreted as not being "hand-held." We believe it is more appropriate to specify that Appendix K addresses "field portable infrared cameras," and that it is unreasonable to require that the camera be hand-held. **We therefore recommend the phrase "hand-held" be deleted from Appendix K everywhere it occurs as a OGI camera descriptor.** Use of the term <u>as an example</u> of an OGI camera operating condition (e.g., in the definition of "Camera Configuration") is appropriate and need not be deleted, though we would suggest "drone" be added as an alternative example of a camera mount in those two cases where "handheld" and "tripod" are identified as example camera mounts.

Many places in Appendix K refer to "regulated components." But there will be locations where there are components regulated under other rules or by non-equipment leak portions of the referencing rule or permit (e.g., process vents) that might be within an OGI's operating envelope. **Thus, for clarity, we recommend the term "regulated component" be changed to "equipment leak component regulated by the referencing subpart or permit."**

In the petroleum operations that Appendix K would apply to under the Initial Methane Notice and in other operations it may apply to under other rules or permits, a "site" can be anything from a single wellhead-only wellsite involving a few potential leak interfaces to a refinery complex involving millions of potential leak interfaces. Thus, monitoring a "site" can take a short time for one OGI operator (hours) or require many fulltime OGI operators and take months to complete. Further, siting and location significantly varies, from rural, remote wellsites spread out miles apart across a basin, to a large, centralized industrial facility. Because of this extreme diversity in size and accessibility, **AXPC recommends "site" not be the basis for any Appendix K requirements, except where the size of the site is not significant** (e.g., the requirement in Section 9.0 that each "site" have a monitoring plan). Specific suggestions for alternatives to each use of "site" in the draft Appendix K where we believe a change is needed are included below.

Additionally, there are requirements assigned to the "site" that could be the responsibility of a contract monitoring organization and would apply at multiple sites. These include, for instance, development of procedures that describe how components will be viewed with the OGI camera (paragraph 9.4) and the requirement to have a plan for avoiding camera operator fatigue (paragraph 9.5). **In these cases, we recommend Appendix K provide that either the site <u>or</u> the camera operator's employer be required to have these plans.**

"Number of surveys" performed is a suggested criterion for an operator to be a senior OGI operator, for establishing training requirements, and for other suggested requirements. Given that an individual site survey can take hours or months depending on the size, complexity, etc. of the site, basing any requirement or criterion on the "number of surveys" creates confusion and inequities. In our specific comments below, **we recommend use of hours of monitoring or, in some cases, the number of 20-minute monitoring periods as a more precise and easily managed substitute for "number of surveys."**

Initial training requirements for OGI operators is referred to as "classroom" training throughout Appendix K. Most training today is done through electronic media, often through web-based online modules. Use of the word "classroom" could be interpreted to disallow such common training approaches and instead mandate in-person classroom attendance. Such a strict limitation creates inefficiencies, is inconsistent with modern training approaches, and potentially limits the rate at which new operators can be trained. **AXPC requests the word "classroom" be deleted or revised everywhere it is used.** In some uses, we believe the meaning is unchanged by this deletion, but where necessary, we suggest the term "classroom or web-based training" be used instead.

B. Applicability

Applicability is discussed in Paragraph 1.3. Paragraph 1.3 states "This protocol is not applicable to chemical plants or other facility types outside of the oil and gas upstream and downstream sectors." **We recommend this sentence be deleted.** It is incorrect to assume that Appendix K might not be appropriate for use for <u>some</u> processes in other source categories and there is no reason to preclude that here, since Appendix K <u>only</u> becomes applicable when a referencing subpart, permit, or the Administrator allows and since adequate camera capability is assured by the requirements in Paragraphs 6.1.1 and 6.1.2. and the other Appendix K requirements.

Paragraph 1.3 starts "This protocol is applicable to all facility types from the upstream and downstream oil and gas sectors and may apply to well heads, compressor stations, boosting stations, petroleum refineries, gas processing plants, and gasoline distribution facilities when referenced by an applicable subpart." Consistent with the application of Appendix K to other source categories in the near term, the precedent of leaving applicability decisions to referencing subparts and permits, and AXPC's belief that Appendix K is inappropriate for many of the upstream operations listed, we see no purpose for including this sentence in Appendix K. Nor does it reflect that the protocol addresses equipment leaks, as would be normal for an Appendix protocol. **AXPC, therefore, recommends this sentence be revised to the following: "This protocol is applicable to equipment leak components at facilities when referenced by an applicable subpart."**

C. Definition of fugitive emission or leak

The suggested definition of fugitive emission or leak is "any emissions observed using OGI." **AXPC believes that the definition can only address emissions from equipment components identified in the referencing subpart or permit as being subject to OGI.** Those are the only emission sources that were considered in the referencing subpart rulemaking or permitting process and are the only components that the referencing subpart or permit monitoring and repair provisions address. We agree that other OGI findings must be addressed if the monitoring identifies excess emissions or unauthorized emissions, but such findings are subject to other repair and reporting requirements than those that a referencing subpart or permit imposes for equipment leaks. We recommend the following revised definition:

> *Fugitive emission or leak* means any emissions observed using OGI from any equipment component identified in the referencing subpart or permit as being subject to monitoring using this Appendix (Appendix K).

D. Definition of Repair

Appendix K appropriately requires that, when a leak is identified by OGI monitoring, the leaking component be clearly identified. However, Appendix K does not address repair. Repair requirements are addressed in the referencing subpart or permit, and the referencing subpart or permit may provide alternatives to adjusting or altering the leaking component, which is the only approach mentioned in Appendix K's definition of repair. For instance, it may be possible and allowed to route the leak to a compliant control device. Additionally, the referencing subpart will address how it is to be demonstrated that the repair was successful. For instance, it could require remonitoring by OGI, or it could require remonitoring by OGI or Method 21. **Since repair is addressed in each referencing subpart or permit and not in Appendix K, and the definition in that subpart or permit may be different than the definition suggested in Appendix K, this definition should be deleted.**

E. Definition of Response Factor

The suggested definition of response factor is:

> *Response factor* means the OGI camera's response to a compound of interest relative to a reference compound at a concentration path-length of 10,000 part per million-meter. Response factors can be obtained from peer reviewed articles or may be developed according to procedures approved by the Administrator.

The second sentence of this suggested response factor definition limits response factors to those obtained from peer reviewed articles or developed according to procedures approved by the Administrator. However, there are serious issues with that limitation, discussed below. We believe that the criteria in the first sentence of the suggested definition and in paragraph 6.1.1 of Appendix K is adequate to assure valid response factors. Therefore, **AXPC recommends that the second sentence of the suggested definition be deleted.**

The first issue is that there may be different response factors for different OGI cameras as technology changes and new response factors will be needed as additional applications of OGI are made and as technology changes. Such commercial information is not amenable to publication in peer reviewed articles, nor could such response factors be published in a timely manner. Thus, if anything is to be peer reviewed, it must be the methodology used to develop the response factors. Given the specifics in the first sentence (a path-length of 10,000 ppm-meters) and the specification in paragraph 6.1.1 of propane as the reference compound, it hardly seems necessary to require any review of the response factors themselves.

Secondly, many response factors have been developed by camera manufacturers for current cameras. We are concerned that those response factors, which are currently in widespread use, might not meet the criteria in the suggested definition. While these may have been peer reviewed, they were not necessarily "obtained from peer reviewed articles." Furthermore, we have no idea what procedures the Administrator might require and whether currently used factors will be found to be consistent with that yet undefined procedure.

If the Agency believes such a limitation is needed, it should focus the limitation on the methodology for developing response factors, propose in the supplemental proposal the methodology they plan to require, and grandfather response factors developed prior to that supplemental proposal.

F. Definition of Senior OGI Camera Operator

Some OGI camera operators are certified thermographers. The thermograph certification requirements parallel the initial training requirements that would apply under Appendix K. Thus, **we recommend that certified thermographers be consider as senior OGI camera operators and that they be exempted from the initial training requirements in Paragraphs 10.1 through 10.3.**

Per the discussion in Comment I.3.B, we recommend the suggested definition of senior OGI camera operator be replaced. We suggest the following definition:

> A senior OGI camera operator is an OGI camera operator who 1) has successfully completed the initial and field training specified in Section 10 of this Appendix or 2) is a certified thermographer, and, as applicable, has completed refresher training and performed at least 20 hours of OGI monitoring (excluding their own initial and refresher training time) in the previous 12 months.

"Site" is an extremely unclear and imprecise term, and we are suggesting that 20 hours of recent monitoring experience be specified instead. More critically, we are recommending removal of the "career" experience requirement. We do not believe long experience adds significantly to an operator's ability to train or audit others. It is *recent* experience with current equipment and requirements at locations that are currently being monitored that is critical to quality training and auditing and we believe the 12-month criterion provides that expertise.

We believe this level of experience is adequate to assure the senior OGI camera operator duties are well performed, while expanding the pool of senior operators to assure an adequate supply and the availability of senior people to perform monitoring as well as training and quality assurance functions. **It also should be clarified that monitoring hours performed by a senior operator as a quality check of another operator or operator trainee counts toward the 12-month senior OGI operator monitoring criterion.**
If the definition of senior OGI operator is not changed, we have the following concerns and recommendations on the suggested definition of senior OGI operator.

The direct reading of the suggested definition would seem to require that a senior OGI camera operator must have conducted OGI surveys at 500 "different" sites in their career and 20 "different" sites in the past 12 months. "Site" seems here to mean "*different* sites," making the definition impractical, since most OGI operators, particularly those associated with a single company, will not have access to that many different sites. Further, "site" is at best an inexact term. **Thus, we recommend that the word "site" be removed from this definition.**

G. Site Hazards

Site hazards is found in paragraph 5.1. The final sentence of this paragraph states "It is the responsibility of the user of this protocol to establish appropriate health and safety practices and determine the applicability of regulatory limitations prior to implementing this protocol." **This sentence is inappropriate and unnecessary and should be deleted.** Imposing health and safety requirements, even general ones such as this, is the responsibility of other agencies.

Furthermore, it is the responsibility of all involved, not just the user of this Appendix, to assure a safe and healthy operation. It is EPA's responsibility not to incorporate unsafe requirements into this method. It is the responsibility of the site owner or operator to meet requirements applicable to the site and to establish other requirements it feels are needed. It is the responsibility of the OGI camera operator and his or her organization to meet regulatory <u>and other</u> requirements applicable to workers.

H. Equipment and Supplies

Equipment and supplies are found in Section 6. **AXPC supports the spectral range requirements in paragraph 6.1.1.** Monitored components can contain a wide range of hydrocarbons with a range of individual response factors. It is important to making this methodology feasible to balance the camera's ability versus the wide range of components that may be in an emission and our limited ability to precisely characterize stream compositions. We believe the paragraph accomplishes that balance and cameras meeting this specification will be able to identify emissions of concern.

Paragraph 6.1.2 and its subparagraphs specify a minimum detection limit for methane and butane and various equipment to be used in demonstrating that those minimum limits are met. Requiring this test for every individual OGI camera is unnecessary since all cameras of a particular model are the same. Thus, **we recommend that paragraph 6.1.2 be clarified to indicate that this testing may be performed by the equipment manufacturer for each model camera and configuration they produce.**

Paragraph 6.2.4 calls for use of a mass flow controller or rotameter capable of controlling the methane and butane rates within a National Institute of Standards and Technology (NIST) traceable accuracy of 5 percent when testing a camera. NIST traceability is not specified for any other instrumentation used in these demonstrations and seems unnecessary for this use. **We recommend the requirement for NIST traceability be removed.**
The 6.2.6 subparagraphs specify requirements for weather stations from which data will be used for the minimum detection limit testing required by paragraph 6.1.2. In many cases, National Weather Service stations will be the basis for this data and the testing facility will not have ready access to the instrumentation specifications at that weather station or the ability to influence that equipment. **We therefore recommend that weather data obtained from a National Weather Service Station located within one mile of the test location or the nearest available weather station be allowed without requiring the information specified in paragraphs 6.2.6.1 through 6.2.6.5 to be collected.**

Paragraph 6.2.6.4 contains a typographical error. Wind direction is measured in degrees, not degrees Celsius as indicated in the draft.

I. Camera Calibration and Maintenance

Camera calibration and maintenance are found in Section 7. Our members report their experience with OGI cameras confirms that these cameras do not require any ongoing calibration or routine maintenance. Thus, **we support Section 7 in its current form.**

J. Initial Performance Verification and Development of the Operating Envelope

Initial performance verification and development of the operating envelope are found in Section 8. Paragraph 8.1 requires a record be maintained with other OGI records that each OGI camera meets the minimum detection limit requirements in paragraph 6.1. As indicated elsewhere in these comments, we anticipate it will be primarily the camera manufacturer's responsibility to assure the camera meets those specifications. Many of these cameras will be used at multiple, separate facilities owned by different entities and it would be difficult and lead to a lack of cohesion for every entity that uses the camera and must maintain OGI monitoring records to have to maintain a copy of that documentation. **AXPC therefore recommends this requirement be revised to require that the manufacturer of the OGI camera or other entity that performs the paragraph 6.1 evaluation be required to maintain a record confirming compliance with paragraph 6.1 requirements and that such a record not be required to be**

kept by the camera owner or at each location where the camera is used. Further, we recommend this recordkeeping requirement be moved to paragraph 6.1, where it better fits.

As with the requirements in paragraph 6.1, in most cases establishing operating envelopes per the requirements of paragraphs 8.2 through 8.6 can most efficiently, and with minimum methane and butane emissions, be developed by the manufacturer for each camera model configuration they produce. While there will be cases where a different operating window may be needed for a particular monitoring situation, that will be the exception rather than the rule. In most cases, a single or a few operating envelopes will suffice for most monitoring. The key, which is addressed in Section 9 of Appendix K, is assuring all equipment components are within an established monitoring envelope when they are monitored. **We, therefore, recommend that it be made clear in paragraph 8.3 that operating envelopes may be developed by the manufacturer <u>or</u> by a camera owner or user for each model and configuration of their camera.**

Consistent with our recommendation elsewhere in these comments, **AXPC also recommends paragraph 8.6 be revised to require that the entity that develops an operating window for an OGI camera model or configuration be required to maintain the records supporting that operating window and that not everyone that has to maintain OGI monitoring results must have those records, as the language in paragraph 8.6 would seem to require.** Since the users of an OGI camera need to know what operating windows are applicable, and the parameters for that operating window**, we also recommend that the OGI camera owner or user maintain a record of the operating window parameters that apply for each configuration of their camera.** Again, this needs to be the camera users or owners' responsibility, since many of these cameras will be used at multiple locations owned or operated by many different entities and the camera owner may not even be a facility owner or operator (e.g., a monitoring contractor).

K. Conducting the Monitoring Survey

Conducting the monitoring survey is found in Section 9. **AXPC supports the daily initial verification check in paragraph 9.1.** In our experience, these checks assure the OGI camera is functioning properly.

Paragraph 9.2.1 requires the camera operator to determine daily the "maximum viewing distance from the surveyed components, based upon wind speed and expected delta-T at the monitoring site." This paragraph is redundant and does not add notable value to the protocol, given that some cameras will be used at many monitoring sites in a day and delta-T may vary from one viewing to the next. Considering paragraph 9.2.2, which requires that procedures be in place to assure the monitoring is only conducted within the limits of an operating envelop applicable to that camera, paragraph 9.2.1 is redundant and unnecessary. Therefore, **AXPC recommends that paragraph 9.2.1 be deleted.**

L. Components monitored

Paragraph 9.3 calls for each site monitoring plan to identify monitoring survey methodologies that ensure all regulated components are monitored. It provides only three approaches that may be used. All three approaches are extremely complex, and the burdens imposed are often not justified versus other alternatives. We comment on some of the specifics of the three approaches below, though we believe this paragraph should be replaced in its entirety.

As was found for Part 60 Subpart OOOOa sources (as described below), we believe other approaches to those currently suggested for assuring all components are included are available or will be identified as thousands of monitoring programs are developed and executed and as technology improves. Use of such alternatives should be encouraged where they prove more efficient.

Furthermore, limiting survey monitoring methodologies to only three is inconsistent with the stated intent of the Initial Methane Notice. At page 63,165, EPA states:

> The 2016 NSPS OOOOa, as originally promulgated, required that each fugitive emissions monitoring plan include a site map and a defined observation path to ensure that the OGI operator visualizes all of the components that must be monitored during each survey. The 2020 Technical Rule amended this requirement to allow the company to specify procedures that would meet this same goal of ensuring every component is monitored during each survey. While the site map and observation path are one way to achieve this, other options can also ensure monitoring, such as an inventory or narrative of the location of each fugitive emissions component. The EPA stated in the 2020 Technical Rule that ''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.'' 85 FR 57416 (September 15, 2020). Because the same monitoring device is used to monitor both methane and VOC emissions, the same company-defined procedures for ensuring each component is monitored are appropriate. Therefore, the EPA is proposing to similarly amend the monitoring plan requirements for methane and for compressor stations to allow company procedures in lieu of a sitemap and an observation path.

For these reasons, **we request the Part 60 Subpart OOOOa language in §60.5397a(d)(1) be substituted for paragraph 9.3.** That language is as follows:

> Your plan must include procedures to ensure that all equipment leak components are monitored. Example procedures include, but are not limited to, a sitemap with an observation path or GPS coordinates, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components.

Should paragraph 9.3 not be replaced with the language from Part 60 Subpart OOOOa or an equivalent, we have the following comments on the language in paragraph 9.3.

The three suggested approaches are clearly intended for use at larger operations where many monitoring locations are needed and there is a large infrastructure and significant resources to allow marking monitoring locations or mapping routes. Many locations subject to the current rulemaking are smaller facilities or portions of a facility (e.g., a flow meter station or a tankfield pump station) where monitoring will require one pair of observations (two views of the components) or at the most, a few observations. It is unnecessary and overly burdensome to have to manage repetitive route maps, to place and maintain monitoring location markers, or even to identify GPS coordinates in such situations.

Thus, if section 9.3 is not replaced, **we recommend an additional option be added that would apply to locations where less than ten monitoring observations are needed to monitor all components regulated by a referencing subpart or permit.** Under that option, the monitoring plan would allow for a description of the approach that will be used (e.g., monitor all components from two views at least 90 degrees apart) and a list of the facilities or facility locations to which this option applies.

For the reasons discussed above, **we recommend the word "site" in paragraph 9.3 (if maintained) be removed. We suggest the paragraph start with "Conduct monitoring using …"**

We also recommend the wording of paragraph 9.3 sentence two, if maintained, be clarified to indicate that a mix of the options is allowed if all components subject to OGI monitoring under the referencing subpart or permit are monitored. As it currently stands, that sentence appears to require the use of the same option for an entire facility. For larger facilities and facilities with a mix of densely located components and remote collections of components, use of a mix of the options may be most efficient.

In paragraph 9.3 (if maintained), we also recommend the last sentence be clarified to indicate that a component database is not required.

Given the massive number of route maps, GPS coordinates, and site lists that must be recorded and maintained if this provision is not replaced, **it is critical that it be clarified that this information may be in electronic form (e.g., databases, spreadsheets) and not "included as part of the monitoring plan" as required by the draft language.**

Paragraph 9.4 and Table 14-1 specify minimum dwell times for observations. **AXPC requests EPA explain the basis for the dwell time requirements in supplemental proposal**, so we can have a basis for providing informed comment.

Paragraph 9.5 requires that the monitoring plan address camera operator fatigue. It includes specific requirements to address this concern. Imposing specific ergonomic requirements such as those in this paragraph is outside the scope of an EPA method. Furthermore, the approach must be tailored to the situation. For instance, under this rulemaking, most monitoring will be in short bursts with travel time between monitoring locations. Nothing specific is needed in these situations to prevent operator fatigue. In more densely populated situations relief may needed, but the times for breaks need to be matched to the situation. For instance, arbitrarily requiring a break five minutes before lunch or quitting time makes no sense. Similarly, stopping a monitoring round that takes 23 minutes to complete for a break at 20 minutes (as specified in the Initial Methane Notice) is equally nonsensical. Additionally, 20 minutes may be too long between breaks in some situations. For instance, if the camera operator had to climb a hundred-foot tower to perform monitoring or monitor in particularly hot situations.

We do not believe there is a generic approach that would not significantly interfere with the efficient execution of this program and **we, therefore, recommend that all but the first sentence of paragraph 9.5 be deleted**.

Paragraph 9.6 requirements apply to a "monitoring survey," but that is an undefined and ambiguous term and the requirements do not really fit since, depending on the situation, a single site or even a single process unit can take anywhere from less than an hour to many days to complete. Furthermore, we see no value from requiring weather data when monitoring moves from one process unit to another at the same location or at the end of the day. Even where there are large process units, weather does not change significantly because of location changes and end of day weather information is of no use in assuring operating envelope requirements are being met, since monitoring has concluded for the day.

We suggest the following wording changes to paragraphs 9.6.1 and 9.6.2 to address this variability:

> 9.6.1 For each monitoring ~~survey~~ day or change in facility, record the date and approximate start and stop times and the name of facility where the monitoring is performed.
> 9.6.2 At the start of the ~~survey~~ each monitoring day or a change in facility~~, when transitioning to the next major process unit, and at the end of monitoring for a day~~, record the weather conditions, including ambient temperature, wind speed, relative humidity, and sky conditions.

Paragraph 9.7 specifies documentation requirements for leaks found (video clip) and clarifies that no video record is required unless a leak is found. **AXPC supports this paragraph, particularly the important clarification that video records are not required unless a leak is identified.** Obtaining and maintaining video records is a major burden and is only justified where there is a reason, such as where a leak has been identified and a video clip will aid in identifying the location of the leak.

Paragraph 9.7.3 requires a 5-minute per day quality assurance video. The paragraph specifies that the video must document the procedures the operator uses to survey (e.g., dwell times, angles, distances, backgrounds) and the camera configuration. It is unclear how such a video clip would demonstrate compliance with that list of items. For instance, dwell times, angles, distances, and backgrounds will vary for every monitoring occurrence, since they depend on the equipment being monitored, the location of the camera relative to the component locations, the background, and the weather. A video does not show whether the videoed monitoring fits the situation except for the few minutes of videoing, nor does it show whether all operating envelope criteria are being met, even for the situation being viewed. Furthermore, video of camera operators who know they are being videoed is unlikely to be representative. The required quarterly (or, as we recommend, annual) performance audits, proper training, the daily equipment startup checks, and the quality assurance requirements in paragraph 11.1 provide all the appropriate quality assurance much more effectively and efficiently than this video requirement. Furthermore, creating extensive video records that are difficult to reliably store, provide no useful information, and are unlikely to ever be reviewed, imposes a large and overly burdensome mandate. **Paragraph 9.7.3 should be deleted.**

M. Field Portion of OGI Camera Operator Training

Field portion of OGI camera operator training is discussed in Paragraph 10.2. Paragraph 10.2.2 addresses the required field training. It calls for a minimum of:

- Ten site surveys where the trainee is observing a senior OGI operator;
- 40 site surveys where monitoring is performed side-by-side with a senior OGI operator;
- 50 site surveys where a senior OGI operator observes the trainee performing monitoring; and
- a final survey where a senior OGI operator performs a follow-up survey that demonstrates the trainee did not miss any persistent leaks.

There are many serious problems with these requirements as follows.

As discussed above, “site” is an imprecise term and could cover monitoring for an hour at a location with only a few potential leak components or it could cover monitoring for months at a location with hundreds of thousands of potential leak components. Thus, **we recommend the word “site” be deleted from these paragraphs and that these training requirements should be based on monitoring hours as discussed below.**

If we establish a training OGI survey as roughly 20 minutes of monitoring (EPA’s suggested monitoring duration without a break in paragraph 9.5), the approach in EPA’s Methane Notice will require over 34 hours of actual field monitoring training for the trainee and over 17 hours of one-on-one senior OGI operator monitoring time, assuming as discussed below, the required observational items can be done in groups. Obviously, much more time would be required if “survey” is left undefined and thus involved more than 20 minutes of monitoring. Considering set-up, breaks, lunch, equipment relocation, etc. this is over a week of trainee time and half a week of senior operator time (per trainee).

In our experience, 34 hours of field monitoring training is unnecessary to assure well-trained operators. In fact, Texas has concluded only 24 hours is necessary. (*See* 30 TX ADC § 101.153(b)(4)(A)). Based on that experience, the need to train large numbers of OGI camera operators initially and the excessive cost and waste of resources associated with this amount of training, **we recommend no more than 24 hours of field monitoring training be required, field training require monitoring surveys of no more than 20-minutes each, and that it be clarified that the observational portions of the training do not have to be one-on-one**. We amplify on this recommendation in the following comments.

Paragraph 10.2 requires 10 surveys where the trainee observes a senior operator, 40 surveys side-by-side with a senior OGI operator and 50 surveys with a senior operator overseeing the trainee. In our experience, this is excessive, particularly the amount of side-by-side surveying. Nor, as discussed below and elsewhere, will there be enough senior OGI operators to perform these functions if the requirements for reaching senior operator status are unchanged. We believe side-by-side monitoring can be done with operators meeting our suggested revised senior OGI camera operator definition with no loss in quality versus senior operator's meeting the definition in EPA's Methane Notice. It is also important that the revised language be clear that the observational training does not have to be one-to-one (see our suggestions in the Appendix K). Thus, **we recommend these requirements be revised to ten 20-minute monitoring surveys where a group of trainees observes a senior OGI camera operator, 50 20-minute monitoring surveys where a senior operator oversees a group of trainees, and five 20-minute monitoring surveys side-by-side with a qualified operator.** The suggested final survey test in paragraph 10.2.2.4 (modified as discussed below) would complete the training. This would provide a total of 23 hours of field experience for each trainee prior to their starting to perform monitoring surveys.

N. Final test

Paragraph 10.2.2.4 requires a final monitoring test where the trainee conducts an OGI survey and a senior OGI camera operator follows behind with a second camera to confirm the OGI survey results. Consistent with our recommendation for performance audits below, **we recommend this final test be of one-hour duration (e.g., three 20-minute periods) to assure a significant number of components are monitored.**

The criterion for passing this final test is "The trainee must achieve zero missed persistent leaks relative to the senior OGI camera operator …." We believe the criterion of zero missed persistent leaks is unreasonable and should be revised. *First*, even if the follow-up survey is performed immediately after the trainee's survey, there can be changes in leak rates, local weather, interferences, etc. that occur and can cause a marginal leak to be observed in one survey and not the other. *Second*, "persistence" is an imprecise term. A leak may occur continually through a dwell period and still be intermittent and thus not meet the definition of a persistent leak or show up in one or the other survey. Additionally, camera placements can be slightly different, so a leak might be observed in the operating window of one survey and not in another. Thus, it is quite possible in the real world, that a leak can be observed in one survey and be believed to be persistent and then not occur in another survey even a few minutes later. Furthermore, this can occur for either survey. In the real world, it is just as likely the trainee will observe leaks that the qualified operator does not. As it currently stands, paragraph 10.2.2.4 presumes the senior operator monitoring always observes more leaks than the trainee observes. That is unreasonable and the passing criteria must allow for either situation. For these reasons, **we recommend that the criterion for passing the final test be changed to at least 90 percent agreement or a difference of no more than one persistent leak if less than ten persistent leaks are identified.**

Paragraph 10.2 is silent as to what is required if an OGI operator trainee fails the final test required by paragraph 10.2.2.4. **AXPC recommends that if 90 percent agreement is not achieved, the senior operator should work with the trainee on the reasons for the failure and then the test should be repeated.** In the case of a second failure, the trainee should be required to go through the refresher level of training prescribed in paragraph 10.3. A "one and done" failure construct creates arbitrary barriers to developing a qualified workforce.

O. Refresher training

Paragraph 10.3 requires annual refresher training for OGI operators. In our experience, annual refresher training is unnecessary considering the ongoing quality assurance requirements and **we recommend the refresher training be on a three-year interval, except for operators that have not completed any monitoring within the last 12-months.** Operators with no monitoring in the last 12-months should be required to complete refresher training before returning to monitoring.

There are a number of OGI programs already underway and thus there are some experienced camera operators already in place. It would be unnecessarily burdensome for them to have to go through the entire initial training program when they first must meet Appendix K requirements. They would only need to understand the specific requirements of this Appendix. Thus, **we recommend that an OGI camera operator with at least eight hours of OGI monitoring experience in the previous 12 months and no previous Appendix K experience only be required to go through the refresher level of training rather than the full initial training.**

P. Performance Audits

Paragraph 10.4 requires quarterly performance audits. Our experience suggests that formal quarterly audits of camera operators are excessive.
In fact, it is unclear that such performance audits are useful at all. We note that the Method 21 program has been successfully in service for more than 40 years without a similar audit requirement. Considering the requirements for an on-going quality control program in paragraph 11.1, annual performance audits are adequate to assure that a camera operator is correctly monitoring and lessens the demand for audit resources. **We recommend changing this requirement to annual audits**.

This change has the added benefit of reducing the demand on senior OGI camera operator time, thereby reducing Appendix K burdens and allowing more time for senior operators to do monitoring and training.

Paragraph 10.4.1 outlines a performance audit option using comparative monitoring and paragraph 10.2.2 outlines a performance audit option using video review. **We support providing alternative audit approaches,** since there will be many variants in monitoring organizations, monitoring schedules, senior OGI camera operator availability, and facilities, but believe there should be more than two alternatives allowed. Therefore, **we also recommend that the performance audit methodologies be required to be included in the monitoring plan as already implied in paragraph 11.1 and that these two approaches only be cited as examples.**

Paragraphs 10.4.1.1 and 10.4.2.1 require audits of at least four hours with no persistent leaks identified by the auditor that were missed by the auditee. Four hours is an excessively long period and is not needed to assess if an auditee is monitoring correctly. Nor is it a reasonable use of resources, tying up an OGI camera operator and an auditor for more than a day per audit (four hours for the trainee monitoring and four hours for the follow-up senior OGI operator survey). In addition, in the case of upstream, most sites are small and not very complex. The requirement could end up necessitating multiple site visits with travel time in between, thus extending the working time for the personnel. **We recommend the four-hour requirement be changed to require audits of one hour total duration (i.e., three 20-minute periods) and these audits only be required annually.**

We also recommend that the criterion for passing the audit be changed to at least 90 percent agreement of the number of persistent leaks found or a difference of no more than one persistent leak if less than ten persistent leaks are identified.

We also request EPA make clear that these audits may be performed by the OGI camera operator employer or a site owner or operator and there is no requirement for additional audits as the camera operator moves from one site to another or from employer to employer.

There is a typographical error in that paragraph 10.4.2.2 is labelled as 10.4.2.3 in the draft Appendix K.

Paragraphs 10.4.1.2 and 10.4.2.2 specify retraining requirements for an operator that fails the audit criterion. The retraining requires a minimum of 1) ten site surveys where the trainee is observing a senior OGI operator, 2) five site surveys where monitoring is performed side-by-side with a senior OGI operator, 3) ten site surveys where a senior OGI observes the monitoring and 4) a final survey where a senior OGI operator performs a follow-up survey that demonstrates the operator in training did not miss any persistent leaks. *First*, **we recommend the word "site" be deleted from these paragraphs**. *Second*, we believe the retraining that the Initial Methane Notice suggests is excessive and overly burdensome.

Failures to observe a leak or to follow some aspects of the monitoring procedure are situation specific. General retraining dilutes the focus on the real problem and uses up precious monitoring time and senior resources on issues that are not a problem. Therefore, we believe it is impossible to specify a retraining paradigm that is generic and resource efficient. Rather, **we believe the requirement should be to specify that retraining is required to address monitoring aspects observed to be an issue during the audit and that the auditee must then pass a new comparative audit by achieving at least 90 percent agreement on the number of persistent leaks or a difference of no more than one persistent leak if less than ten persistent leaks are identified.**

Q. Returning Operators

Returning operators are discussed in paragraph 10.5. This paragraph states "If an OGI camera operator has not conducted a monitoring survey in over 12 months, then they must repeat the initial training requirements in Section 10.2." This seems excessive for an experienced operator who has been temporarily in another job or out due to an extended sickness. Rather, **we recommend the returning operator be only required to take refresher training and to pass a performance audit. Furthermore, for clarity, we recommend this requirement be integrated into paragraph 10.3 on refresher training.**

R. Quality Assurance and Quality Control

Quality assurance and quality control are discussed in Section 11. Consistent with our recommendation in Comment II.11.H to delete Paragraph 9.7.3, **the second sentence of paragraph 11.2 should be deleted.** We have commented individually on the QA/QC requirements contained throughout. **Paragraph 11.3 summarizes those requirements and will need to be updated to match the final version of the Appendix.** Additionally, some of the wording in the frequency column of that table is unclear as to who is responsible and how often and on what basis the QA/QC activity is required.

S. Recordkeeping

Recordkeeping is discussed in Section 12. As indicated in the following specific comments, "facility" is the wrong basis for requiring most records. Many of the required records will be developed by the camera manufacturer. Others should be housed in owning or operating company central repositories because it is more efficient and because some sites subject to these requirements are not continuously staffed and have no onsite recordkeeping facilities. Training and other operator records should be handled by the camera operator's employer, often not the owner/operator of any facility being monitored. Nor would it be manageable or sensible to require copies of these various records to be made for each of the facilities that will be subject to monitoring.
Thus, as suggested more specifically below, we recommend the word "facility" be deleted from this section and the appropriate entity (e.g., camera owner, facility owner or operator, camera operator employer) be substituted or no specific entity be identified as having to maintain the record. Consistent with this change, **the general recordkeeping requirement in paragraph 12.1 should be generalized to "Records required by this Appendix must be kept for a period of five years, unless otherwise specified in an applicable subpart."**

Paragraph 12.2 says "The facility must maintain the following records in a manner that is easily accessible to all OGI camera operators:" However, except for paragraph 12.2.1 (the site monitoring plan) and 12.2.4 (operating envelope limits) the other listed records are associated with the camera and many cameras will be used at multiple facilities and may not be owned by the facility or even the facility owner. In fact, it can be anticipated that many cameras will be owned by a monitoring company. **Thus, "facility" should be deleted from the paragraph 12.2 wording, and it should be rephrased to say, "The following records must be maintained, as applicable."**

Paragraphs 12.3 requires records of data supporting development of the operating envelope. We anticipate most, though not all, operating envelope development will be done by the camera manufacturer and thus **paragraph 12.3 should require operating envelope supporting data to be maintained by the developer of the operating envelope.**

Paragraph 12.4 contains requirements applicable to camera operators. These records are the purview of the operator's employer and not, in most cases, individual facilities or even operating companies. **Paragraph 12.4 should be clarified to require these records to be maintained by the camera operator's employer or facility owner or operator as applicable.**

Paragraph 12.4.3 appears to require records of operator training activities but starts by requiring "The number and date of all surveys performed . . ." Records of actual monitoring surveys need to be maintained by the owner or operator of the site monitored and are covered by paragraph 12.5. Thus, this introductory phrase in paragraph 12.4.3 needs to be limited to surveys associated with training. If some of those training surveys are performed to locate leaks, records will need to be maintained with the training records required by paragraph 12.4.3 and, also, with monitoring records as required by paragraph 12.5. **We therefore recommend the introductory phase in paragraph 12.4.3 be revised to "The number and date of all training surveys performed . . ."**

Paragraph 12.5 deals with monitoring records and requires that the listed records be available to the technicians' executing repairs. Yet, most items are not associated with repairs or locating the leak and it is overly burdensome to require that they be made available, particularly if the monitoring is not being performed by an employee of the site being monitored. **Therefore, we recommend only paragraph 12.5.6 be required to be available to the repair technicians**.

APPENDIX B - SPECIFIC COMMENTS IN RESPONSE TO EPA'S REQUESTS FOR SOLICITATION ON SELECTED TOPICS RELATED TO THE REGULATION OF LIQUIDS UNLOADING

A. Flaring as a Control Option for Liquids Unloading:

EPA solicits comment "about the use of control devices to reduce emissions from liquids unloading events," after explaining that, "[b]ased on feedback received on the technical and cost feasibility of using a flare to control vented emissions from liquids unloading events indicating that a flare cannot be used in all situations, we did not consider this option any further in this proposal." 86 Fed. Reg. at 63,213/3.

One peer-reviewed study, which EPA itself cites (86 Fed. Reg. at 63,213/3 n. 274), stated "'The flowing characteristics during venting operations inhibit the design of flare equipment. During the unloading operation, initial gas flow rate and pressure are high and decline rapidly over a short time period. Flare design (tip diameter) is based on flow rate and design criteria can be found in Radian Corporation/EPA 1995 Report – Chapter 7 on Flares. In addition, the sporadic nature of liquids unloading venting operations would require either a continuous pilot or electronic igniter. The design cost associated with the requirements needed for this type of flow would be cost prohibitive.' Additional information for flare applicability in this context is available in EPA Gas Star PRO Fact Sheets No. 904 'Install Flares' and No. 903 'Install Electronic Flare Ignition Devices.'" (Footnote omitted).

While EPA's choice to not consider a flare as a control option for unloading events could be justified with respect to some operational scenarios, there are opportunities to use flares in many cases and these cases are likely the ones that offer the biggest opportunity for methane emission reductions. As an example, consider the methods of liquids unloading that use an artificial lift engine, e.g., gas lifting the fluids with compressed gas. In this example, the well still may require a very low surface pressure to effectively remove the liquids and the quantity of produced gas could be significant before it can be directed to sales or recirculated into a gas compressor intake. Certainly, a flare as a control device in this situation would be technically feasible and likely result in a safer operation. Therefore, flares should be considered as a control option in this rulemaking, and an unloading event controlled with a flare should be considered as non-venting liquids unloading. Additionally, Enclosed Combustion Devices and Thermal Oxidizers should be considered as well.

Production Engineers attempt to capture methane emissions and put them into the sales line when practical. During plunger lift, gas lift assist, soap assist, venturi system lift, swabbing, and many other forms of liquids unloading, gas is often captured and routed to sales or to a control device, e.g., flare, compression input, heaters, generators, etc. Again, this is in line with EPA's observation, at 86 Fed. Reg. 63,211, that "Selecting a particular method to meet a particular well's unloading needs must be based on a production engineering decision that is designed to remove the barriers to production." In many cases there are ways to achieve this with going to sales or a control device, but when an operator can no longer do so, they still need to be able to vent. There are many Gas Star Partner Reported Opportunities (PROs) that address the cost side of these solutions that are highly variable.
In various state approved BMPs (NM, PA, CO), there are common elements which are non-prescriptive and allow for operators to employ their expertise in the selection of appropriate liquids unloading practices. The commonality or consistencies of these elements reflects recognized and common practices that are proven. AXPC recommends that EPA consider the application of these common elements in determining the minimum elements requirements. One such common practice is to require monitoring during a liquids unloading event via the presence of an operator on-site or in close proximity. Remote monitoring via sensor technology may also be employed, as feasible.

We also urge that for states where a BMP governing liquids unloading events is required under the state's New Source Review (NSR) program, such BMPs should be deemed sufficient to satisfy the requirements of NSPS with regard to liquids unloading. Congress designed NSR to be at least as stringent as the NSPS program, see CAA § 169(3) (defining Best Available Control Technology, the standard applicable under NSR, as an emissions limit that "[i]n no event" shall result in more emissions than those allowed under any applicable standard under 111). Therefore, a source's NSR-derived requirements for an activity should be deemed to satisfy the requirements of the NSPS. Doing otherwise would contradict the statute and impose unnecessary duplicative regulations for no additional emissions benefit. This would be doubly inappropriate under the state-planning process under 111(d), given the strong and explicit textual commitment to federalism and state flexibility in that subsection's text and structure. EPA must allow states to incorporate into their state plans under new subpart OOOOc their NSR provisions for sources' liquids unloading events. To do otherwise would violate the cooperative-federalist design of not one but two portions of the statute: 111(d) and the states' NSR programs as incorporated in their State Implementation Plans under 110.

B. Percentage of Liquids Unloading Events that Vent to the Atmosphere

"The EPA solicits information on the number (or percent) of liquids unloading events that vent to the atmosphere versus do not vent to the atmosphere under normal conditions and whether there are technical obstacles (other than costs) that would not allow liquids unloading to be performed without venting." 86 Fed. Reg. at 63,212/3.

Production Engineers should be empowered to make the best production decision, and when they decide venting is required, it should be considered technically necessary. The following are examples of technical obstacles that would not allow liquids unloading to be performed without venting:

- Many wells need to unload to an atmospheric tank for unloading to be successful.
- Sporadic unloading is difficult to model and the selection of surface equipment that does not vent creates safety concerns.
- Separation equipment requires threshold operating pressures and performs poorly under sporadic flow.
- The use of compressed nitrogen to unload wells often requires some venting.
- High surface producing pressures can result from gathering and compressor system maintenance or unplanned upsets. Wells often cannot unload against these higher surface pressures.
- Locations are often too small to accommodate the significant amount of equipment which would be necessary for non-venting liquids unloading.

Almost all non-venting liquids unloading events are done against a surface back pressure that is greater than atmospheric pressure. Even small amounts of back pressure, such as unit increases in psi, could dispositively determine whether an unloading attempt is successful or not. Many wells will not unload against surface back pressure and therefore require venting to the atmosphere.

Due to the variable nature of liquids unloading operations, attempts to contain the surging fluids and gases becomes a very difficult design problem. Engineering equations are not available to accurately estimate the pressure affects as the fluid stream reaches the surface equipment. Therefore, having a totally closed system without the ability to vent to the atmosphere, in many cases creates a safety concern, i.e., potential bursting of tanks. To completely prevent any issues like the bursting of separators or tanks, while keeping the surface pressures low, the surface equipment would need to be designed with safety factors that would result in significantly overrated and oversized equipment with the associated excessive cost. This is not a practical solution, especially for low producing wells.

Additionally, much of the surface equipment needed for the separation of gas from liquids requires a threshold operating pressure and a flow regime that is not significantly sporadic. To be able to measure and control unloading emissions this separation would need to be completed. This is often not practical unless tanks that can vent to accumulate the sporadic flow stream are used which allow for liquid/gas gravity separation over time.

The use of compressed nitrogen to unload wells is common practice, especially when a well does not have the ability to use produced gas, e.g., a single well on a location, an exploration type well without any gathering infrastructure, etc. Since the unloading gas stream will be a mixture of the injected nitrogen and formation gas the gas will have too high a nitrogen content to put in a sales line or to burn efficiently via a flare. Until the mixture can go to beneficial use, some venting may be necessary. These operations make all attempts to minimize this venting, typically with a recirculation system.

In certain basins/formations, a temporary shut-in to build pressure does not build enough delta between bottomhole pressure and surface pressure to overcome the production impediment caused by liquid holdup. Therefore, unloading to a low-pressure system is required.

Even in circumstances where a non-venting solution may be possible, the amount of equipment, additional artificial lift engines, and associated secondary emissions, often makes it an obviously poor choice. Location size can also prevent the installation of any such equipment, particularly when there is not adequate and prudent spacing between wellheads and other potential ignition sources and fired equipment such as compressor exhaust and flares. Production Engineers are professional problem solvers, and they should be empowered to come up with the best solutions, as discussed in the preceding comments.

We therefore agree that venting should be permitted and that BMPs should be followed to minimize any associated emissions.

C. Routing Emissions to a Sales Line or Back to the Process

"The EPA is soliciting comments about the option to collect and route emissions back to the sales line or to a process. Specifically, we request information on the types of wells and unloading events for which this option is feasible (if any). If this option is feasible, we also request information on the specifics of the equipment and processes needed to accomplish this, as well as the costs." 86 Fed. Reg. at 63,214/1.

The routing of emissions back to a sales line is often at least theoretically possible, but is not always practical, and does create secondary emissions.

One operator uses mobile gas lift compressors (MGLC) to unload wells to minimize venting emissions. The estimated cost for routing unloading emissions to the sales line using mobile gas lift wellsite compressors for one operator is $280,000 per year. The equipment size, layout, spacing requirements (Fire Class/Divisions), and cost would make it difficult to justify for use on marginal or remote wells. The secondary emissions from the model 3406 gas-powered compressors are approximately 4 tons per event CO2*e*.

D. Cost Analysis

The CAA requires EPA to consider cost when promulgating standards under Section 111. AXPC believes EPA's method of establishing cost reasonableness with respect to liquids unloading is inadequate.

The Initial Methane Notice does not adequately analyze the cost of requiring all liquids unloading events to be non-venting, which, in addition to the other reasons discussed in these comments, is another reason why that suggested requirement should not be finalized.

EPA's general approach is to determine cost-reasonableness by considering the cost in dollars per tons of emission reduction, yet EPA's analysis does not appear supported by actually observed emission reductions. EPA acknowledged that establishing an emission reduction that would be achievable per liquids unloading event is difficult, because the baseline level of management practices and emissions varies significantly. Therefore, EPA calculated the $/ton reduction from the baseline level based on hypothetical values of 10 percent, 25 percent, and 50 percent. As stated, these are hypothetical values. Therefore, their utility in representing reduction-per-event is questionable at best. Additionally, the baseline emission is a crucial factor in calculating the tonnage of reduction, yet EPA has not transparently provided a justification for the baseline emissions applied in the calculation of cost reasonableness. As such, we do not believe that EPA's Initial Methane Notice presents an adequate analysis with regard to the cost reasonableness of the "Non-Emitting Evaluation" option.

To establish the cost reasonableness for existing sources, that is, wells already equipped with "non-venting" technology such as plunger lift, EPA's analysis is based on 2015 – 2019 liquids unloading data from the GHGRP. The data shows 98 percent of "with plunger" wells are those equipped with an automated plunger for which EPA cannot establish an emission reduction baseline. Hence, the analysis is based on the remaining 2 percent of the well population representing manual liquids unloading operation. We question this analysis, because 98 percent of actual wells are equipped with an automated plunger system, based on which EPA cannot establish a representative estimate of actual reduction for the overwhelming majority of wells.

The analysis for velocity strings was incomplete and generally not applicable to a wide variety of unloading challenges.

The analysis for use of velocity strings is not applicable to fields where the potential well-to-well communication exists during normal prudent field development. In these cases, a significant amount of water will result in legacy offset wells and velocity strings will make the recovery and deliquification of these wells extremely difficult or impossible as the conduit, with reduced diameter, would create significant friction and back pressure.

Velocity strings also are very difficult to unload. Swabbing and plunger options are either reduced or eliminated due to the small diameter.

Velocity string sizing requirements change with time requiring replacement. They are therefore not considered permanent solutions for liquids unloading. The increased emissions and cost arising from the use of velocity strings was not considered in EPA's analysis.