October 2, 2023

Submitted electronically to docket No. EPA-HQ-OAR-2023-0234

Jennifer Bohman

Climate Change Division, Office of Atmospheric Programs (MC-6207A)
Environmental Protection Agency
1200 Pennsylvania Ave. NW
Washington, DC 20460

Re: Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems; Docket No. EPA-HQ-OAR-2023-0234

Dear Ms. Bohman:

The American Petroleum Institute, the American Exploration & Production Council, Independent Petroleum Association of America, The Petroleum Alliance of Oklahoma, and the American Fuel and Petrochemical Manufacturers (collectively "Industry Trades") appreciate the opportunity to offer comments to the U.S. Environmental Protection Agency (EPA) on the proposed "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems" (proposed on August 1, 2023). For perspectives of offshore operators, the Industry Trades encourage EPA to also review the Offshore Operators Committee (OOC) letter and incorporate them by reference herein. With this submittal, the Industry Trades seek to continue our participation in the rulemaking process as a collaborative stakeholder by providing meaningful solutions to simultaneously address EPA's goals while addressing the burden of data collection (and identifying potential unintended consequences) that could result if the rulemaking is finalized as proposed.

The oil and natural gas industry has participated as key collaborative stakeholders, advancing the EPA Greenhouse Gas Reporting Program (GHGRP) since its inception by contributing expertise and proposing alternatives that reflect the reality of the industry and its evolving day-to-day operating practices. The Industry Trades have focused on providing information that will help inform decision makers and the public about various challenges to data collection and reporting required by the rule, which includes safety, accuracy, and feasibility concerns, as well as the need to protect sensitive information and to ensure that reporting requirements are placed on the correct reporters.

These comments on EPA's proposed revisions to Subpart W reflect our continued interest in the evolution of the GHGRP to provide an accurate accounting of greenhouse gas (GHG) emissions from facilities across the full value chain of the oil and natural gas industry. Our comments cover concerns and recommendations in the wide range of sectors that relate to the operations of our collective members.

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INDUSTRY TRADES' INTERESTS

The **American Petroleum Institute (API)** is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. GDP. API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators and marine transporters as well as service and supply companies providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader convening subject matter experts from across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 800 standards to enhance operational safety, environmental protection, and sustainability in the industry.

Additionally, API has a history of working with EPA to refine and improve data collection, emission estimation and emission reporting under various subparts of the GHGRP. API has worked with both EPA and the regulated industry for more than two decades in developing methodologies for estimating greenhouse gas emissions from oil and natural gas operations. API's first *Compendium of GHG Emissions Methodologies for the Oil and Natural Gas Industry* (the *Compendium*) was published in 2001. As reflected in EPA's efforts to revise the GHGRP and API's recent publication of a 4th edition of the *Compendium* *(November 2021)*, methodologies to estimate and measure greenhouse gas emissions are continually evolving.

The **American Exploration & Production Council (AXPC)** is a national trade association representing 30 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 providing positive environmental and public-welfare outcomes and responsible stewardship of the nation's natural resources. It is important that regulatory policy enables us to support continued progress on both fronts through innovation and collaboration.

The **Independent Petroleum Association of America (IPAA)** represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, which will be significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 91 percent of oil and natural gas wells in the U.S., producing 83 percent of oil and 90 percent of natural gas in the U.S.

The **Petroleum Alliance of Oklahoma** (The Alliance) represents more than 1,400 individuals and member companies and their tens of thousands of employees in the upstream, midstream, and downstream sectors and ventures ranging from small, family-owned businesses to large, publicly traded corporations. The Alliance's members produce, transport, process and refine the bulk of Oklahoma's crude oil and natural gas and play an essential role in providing products and solutions to improve human health and welfare, power the global economy, and make modern life possible. Abundant, clean-burning natural gas has enabled the United States to become the global leader in greenhouse gas emissions reductions. The Alliance's members have and will continue to deploy technologies that result in meaningful greenhouse gas emission reductions through innovative solutions and breakthrough technologies while meeting the energy demands of today and the future.

American Fuel and Petrochemical Manufacturers (AFPM) is a national trade association whose members comprise most U.S. refining and petrochemical manufacturing capacity. AFPM is the leading trade association representing the makers of the fuels that keep us moving, the manufacturers of the petrochemicals that are the essential building blocks for modern life, and the midstream companies that get our feedstocks and products where they need to go. To receive necessary materials and to move their essential products to satisfy growing demand, AFPM members depend on the timely development of, and enhancements to, transportation infrastructure such as pipelines.

The Industry Trades appreciate EPA's engagement and responsiveness to our questions during the comment period. We remain committed to working constructively with EPA and the Administration to finalize changes to Subpart W that improve accuracy without imposing undue burden on the industry, reflect technological and scientific improvements in methodologies, and incentivize the industry's ongoing efforts to reduce emissions.

The Industry Trades' Comments on EPA's Proposed "Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems"

Docket ID: EPA-HQ-OAR-2023-0234

October 2, 2023

Summary of Priority Items

The Industry Trades support certain aspects of the proposed revisions to Subpart W and remain committed to working with the Environmental Protection Agency (EPA) and the Administrator to improve the accuracy of Subpart W reporting in a cost-effective manner, while encouraging continued progress toward reducing greenhouse gas (GHG) emissions. The Industry Trades support accurate emissions reporting for many reasons, however it is particularly important given that reported emissions will form the basis of assessed methane fees as a Waste Emissions Charge (WEC), implemented under the Inflation Reduction Act (IRA). As such, these proposed changes create a potentially significant financial impact on the Industry Trades. Therefore, the Industry Trades provide these comments with a goal of improving accuracy of reported emissions through requirements that are appropriate, implementable, and reflective of actual emissions.[1] The comments herein focus on technical and feasibility challenges with specific provisions that EPA included in the proposed Subpart W rule revisions, while providing viable alternatives that support accurate emissions reporting.

The Industry Trades continue to strongly encourage EPA to find ways to make Subpart W less prescriptive and therefore better poised to not just accommodate but encourage the use of rapidly evolving technologies to detect and minimize emissions.

In addition to our technical comments, the Industry Trades have identified four overarching priority items within the proposed rules that if satisfactorily amended, will allow industry to attain the maximum potential methane mitigation and reduce public confusion. These high priority items are as follows:

1. **<u>Achieve greater inter- and Intra- agency regulatory harmonization and coordination</u>**:

   There are multiple federal agencies and distinct departments within agencies that have pending or proposed regulations, guidance, or frameworks directly and indirectly related to methane emissions applicable to our industry, as listed below:

   a. EPA – New NSPS OOOO b/c regulations
   b. EPA – Revisions to GHG Subpart W methane reporting
   c. EPA – Pending Methane Emissions Reduction Plan (MERP) implementation regulations
   d. Treasury Department – Section 45V regulations for hydrogen production tax credit, with the treatment of differentiated natural gas
   e. DOT/PHMSA – LDAR Rule
   f. DOI/BLM – Waste Prevention Rule
   g. DOE/Argonne – GREET Model, used as the basis for calculating GHGs associated with hydrogen production for eligibility for the Section 45V tax credit
   h. DOE – Differentiated Gas Framework
   i. State Department – International methane MRV standard (with DOE)
   j. State Department – Global discussions on an EU Import standard and global methane policy

[1] Citations provided in this comment letter refer to the proposed rule, unless indicated otherwise. The structure and order of our comments does not necessarily reflect the individual comments' importance to the Industry Trades and their members. The Industry Trades believe all of its comments will help ensure the rule's integrity and deserve serious consideration.

Across all of this methane-related policy making, the Industry Trades identify a potentially high risk for inconsistent methodologies or reporting structures.

In addition, many states – especially New Mexico and Colorado – have already implemented regulations to mitigate emissions across the oil and gas industry; these likely conflict with the final NSPS OOOOb, EG OOOOc and Subpart W reporting requirements.

We urge EPA to seek true alignment and harmonization with other federal regulatory requirements, particularly the NSPS OOOOb and EG OOOOc "Methane Rules" and the GHGRP itself. Below are a few examples that are articulated in our comments:

- "Other large release events" should be governed by the Methane Rules Super Emitter Response Program ("SERP"), not by an additional and separate Subpart W notification process.
- The "Other large release event" threshold for pipelines should align with the PHMSA incident threshold.
- Compressor vent measurements should align with the Methane Rules. Subpart W should not mandate additional measurements for those sources.
- Flare requirements should not extend beyond 60.18 "General control device and work practice requirements" and the Methane Rules.
- Combustion emissions for all oil and gas segments should be reported under Subpart C, which is the subpart under which *all other industries* report fuel combustion emissions.

2. Incentivize Cost-Effective Advanced Methane Detection through Technology Agnostic Rules:

Advanced methane detection technologies and flexibility to implement them are critical to the industry's ability to fully realize methane emissions reductions. Many operators have invested in technological advancements and have deployed and tested the technologies over many years, demonstrating the success of advanced programs and reaching a firm understanding of their operation and deployment. If this component of the suite of methane rule makings, including in Subpart W, is not expanded, the remaining rules will fail to realize the emission reduction goals.

3. **Accommodate Empirical Data, as a Demonstration of Emission Reductions**:

Provisions must be built into the Subpart W rule so that each operator can demonstrate actual reductions; this would promote consistency, transparency, and accuracy in emissions reporting. For example, reporters are precluded from using readily available empirical data (such as engine performance tests) and are instead required to use static emission factors that were based on limited data sets, which will not be reflect emissions reductions and will disincentivize emission reductions. The Industry Trades have noted throughout our comments where EPA must adjust the rule to accommodate empirical data.

4. **Maintain EPA's GHGRP and Subpart W within it as the Authoritative Source of Reported Emissions**:

There are increasing instances of conflict between Subpart W methodologies with those of permitting agencies, which also conflict with current and proposed LDAR requirements and other state and federal GHG reporting structures. EPA must strive for consistency across all GHG reporting frameworks in order to promote stakeholders' trust and confidence in the data.

In addition to the high priority items listed above, the summary below includes the key comments that are generally applicable to many of EPA's proposed revisions to the Subpart W rule:

- **Many proposed Subpart W requirements would impose high implementation burdens for small accuracy improvements for most sources and overall reported emissions.** This overarching theme applies to numerous proposed requirements, especially flare flow monitoring, flare combustion efficiency reporting, gas composition requirements, liquids unloading, and intermittent-bleed pneumatic devices. The Industry Trades have proposed more efficient and feasible alternatives.

- **EPA has not provided qualitative and quantitative justification to rationalize the proposed requirement to disaggregate current reporting levels in the Onshore Production and Onshore Gathering and Boosting industry segments.** The explicitly references existing definitions of facilities in 40 CFR 98 Subpart W, which includes basin-level reporting for the production and gathering and boosting segments. In this proposed rule, EPA has not clarified how its new proposed level of disaggregated reporting to the site-level results in additional value in understanding the key sources of emissions from a basin. A survey performed by API indicates that the proposed Information Collection Request (ICR) pertaining to the proposed rule significantly underestimates the burden for the impacted sectors that would be required to report individual site level emissions and site IDs. Due to the magnitude of the difference, EPA should provide justification in the form of both qualitative and quantitative results of the costs and benefits of this proposed change and how it aligns with the IRA.

- **Generally, the Industry Trades support the optional use of measured data in addition to EPA or company developed emission factors, when the measured data are appropriate.** Allowing reporters the option to use measured data or emission factors (EPA or company-developed) would increase data accuracy and avoid disincentivizing emission reduction measures. While EPA is increasing the sources for which direct measurement is allowed, there are still some methodologies which only allow the use of prescriptive emission factors and parameters with no alternative options (e.g., flare methane destruction efficiency, fraction of un-combusted gas from engines, crankcase venting). While we support the option to use default emission factors and parameters, requiring reporters to use prescriptive emission factors and parameters in lieu of an option to use directly or representatively measured data disincentivizes deployment of emission reduction measures. Additionally, there are some sources where measured data is required to be used, even if the measured data is infeasible, incomplete or potentially unreliable (e.g., flare flow and composition monitoring, mud degassing methane content). EPA should allow operators to utilize the growing number of technologies with quantification capabilities to report empirical data for source categories covered under Subpart W.

- **Monitoring, measurement or inspection requirements (e.g., flare monitoring, etc.) included in Subpart W should be consistent across other air quality programs.** The Industry Trades are concerned with potentially conflicting monitoring or other compliance requirements between the Greenhouse Gas Reporting Program (GHGRP) and future air quality rulemaking under New Source Performance Standards (NSPS) or other air quality programs under EPA's office of Air and

Radiation. The Industry Trades are recommending that EPA remove prescriptive monitoring, sampling or inspection requirements from the GHGRP and instead reference data made available through requirements in other existing regulations. Furthermore, the Industry Trades suggest that EPA not finalize changes to Subpart W until such time that NSPS OOOOb and EG OOOOc have been finalized, and give another opportunity to provide comments on the proposed updates to Subpart W. It is important to the Industry Trades that there is consistency as opposed to conflicting requirements between the GHGRP and future and current rulemaking under other air quality regulatory programs. Finally, the Industry Trades wish to make clear that monitoring methods should not define emission reporting parameters.

- **EPA should avoid any potential double-counting of emissions across source types. The Industry Trades have identified specific areas with the potential for double-counting.** Since it is expected that the GHGRP will be used to determine associated fees within a methane-fee environment, the Industry Trades are extremely concerned about any source and methodology which could result in double counting emissions, and therefore, double fees. Categories that are particularly susceptible to potential double counting are other large release events and unlit flares; and even between flares and unlit flares, where the proposed Tier 3 destruction efficiency for flares includes unlit flares.

- **EPA must set a period over which submitted GHG reports are considered "final" now that reported emissions will be used as a basis for methane fees.** The Industry Trades are concerned about having to resubmit reports for administrative errors or small corrections in emissions given EPA's historical practice of continually submitting questions regarding previously submitted reports. This would lead to an unworkable situation where additional fees will have to be levied or credited for minor changes in emissions in a methane-fee environment. The Industry Trades recommend a 5% facility-wide reported methane emissions error threshold and only require corrections for emission inventories in the last three full data years.

The following key comments reference specific high priority items that pertain to requirements in the Subpart W proposed rule amendments:

- **EPA's tiered approach to flare "combustion efficiency" is flawed and is not supported by the data cited by EPA in the Technical Support Document.** The Industry Trades are concerned that EPA proposes to override decades of precedent on oil and gas flare monitoring and operation established in federal and state regulations, permits, manufacturer guarantees, and performance tests based on the results of just one limited study. As such, the Industry Trades are requesting EPA to allow performance test data for flare methane destruction efficiency, rather than inappropriate National Emission Standards for Hazardous Air Pollutants (NESHAP) requirements, as aligned with EPA's intent to incorporate empirical data. Further and importantly, the Industry Trades have provided additional data to supplement its position that flare "combustion efficiency" should be a minimum of 95%, or arguably even higher based on data from 132 flares tested in the Permian and Bakken. Please refer to Section 3.8.4.4.

- **EPA's requirement to directly meter or use continuous parametric monitoring to estimate flare volume is technically and economically infeasible, and may actually lead to reporting inaccuracies, especially for low-flow streams.** The Industry Trades propose that EPA allows reporters the option to continue to use engineering estimates for flare volume. Please refer to Section 3.8.1.

- **There are significant concerns regarding the "other large releases" category relating to third-party reporting, the lack of clarity around what is considered "credible" information, and the thresholds proposed for the source category.** The Industry Trades are concerned that unqualified third-party reports could unnecessarily increase the reporting burden while not leading to more accurate GHG reporting. The Industry Trades are requesting EPA to provide clear and consistent guidelines across regulatory programs on who would be qualified to provide third-party reports (i.e., the necessary expertise, qualifications, methodology, timeline of sharing detections, etc.). The Industry Trades are also concerned that the use of any credible information may lead to reporters inadvertently using invalid data sources, which can lead to inaccurate emissions and disparity among reporters. Further, EPA's requirement to assume a duration of 182 days if no data is available for the release's start or end date is overly conservative. For these reasons, the Industry Trades request EPA to clearly define the scope of credible information. Further, the thresholds of 100 kg/hr. OR 250 mtCO2e would make events with relatively small durations reportable, which does not appear to be EPA's intent to capture large releases. As such, the Industry Trades request that the thresholds be changed to reflect BOTH a rate and an emissions level per event; at a minimum, the threshold should be changed to '100 kg/hr. AND 250 mtCO2e' (i.e., the 100 kg/hr. rate needs to be paired with a duration of at least 100 hours in order to be equivalent to 250 mtCO2e). Please refer to Section 3.11.1, as well as API's comments in response to Docket ID EPA-HQ-OAR-2021-0317, Section 1 (also included in Annex C of this letter).

- **EPA's assumption that improperly seated thief hatches result in a zero percent control efficiency for controlled tanks is overly conservative and not considered in the TSD. Further, EPA's proposed method to calculate the duration of open thief hatches over-estimates emissions from this source.** The Industry Trades propose that EPA use a bifurcated approach for thief hatches that accounts for when they are fully open or improperly seated, which would have lower expected emissions. Please refer to Section 3.6.2.

- **While the Industry Trades support the flexibility to measure GHG emissions from intermittent bleed pneumatic devices, we request that EPA retain the option to use default population emission factors for sources subject to other regulatory programs.** The Industry Trades do not agree with the requirements to measure and monitor emissions from intermittent bleed devices, especially for sources that will be phased out under the impending methane rules. Please refer to Section 3.1.

- **The Industry Trades request that EPA change both the name and definition of "centralized oil production site" in the Subpart W rule to match NSPS OOOOb and EG OOOOc to align with other federal programs under production for consistency and to reflect how the industry owns and operates these facilities**. EPA has incorrectly included centralized production facilities with gathering and boosting, but should instead include them in the production segment where they belong. The Industry Trades also strongly recommend that EPA delete "associated with a single well pad" from the Onshore Petroleum and Natural Gas Production definition in Subpart W in order to clear up the confusion. Please refer to Section 3.16.

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Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems

Docket ID: EPA-HQ-OAR-2023-0234

The comments presented below are arranged by the order of citation in the proposed revisions to the "Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems."

1. Subpart W and the Waste Emissions Charge Program

EPA must present a clear rationale for adding an additional layer to sub-facility-level (i.e., site level) reporting to the onshore production and onshore gathering and boosting segments.

EPA explains in the Proposed Rule that under the current Subpart W, "GHG emissions and activity data are currently generally reported at the basin, county/sub-basin, or unit level, depending upon the specific emission source.[2]" According to EPA, this reporting method "can present challenges in the process of emissions verification, with corresponding potential impacts on data quality, and it also limits data transparency."[3] To resolve those "challenges," EPA proposes "to disaggregate reporting requirements within the Onshore Petroleum and Natural Gas Production and Onshore Petroleum and Natural Gas Gathering and Boosting industry segments."[4] Furthermore, EPA proposes to require several new site-specific data elements to be reported, including reporting information for individual well identification numbers, well pad identification numbers, and gathering and boosting site identification numbers.[5] In other words, EPA proposes to require site specific reporting in addition to facility-level aggregate reporting.

EPA correctly explains in the Proposed Rule that "[u]nder CAA section 136, an ''applicable facility'' is a facility within nine of the ten industry segments subject to subpart W, as currently defined in 40 CFR 98.230 (excluding natural gas distribution)."[6] As currently defined for onshore production and gathering and boosting, facilities in these segments are generally defined as the equipment located in a single hydrocarbon basin under common ownership or control. The meaning of the term "applicable facility" is key to implementation of the WEC because the applicability of that program and potential fees are determined on an "applicable facility" basis.[7] In the IRA, the definition of an "applicable facility" in the onshore production and gathering and boosting refers to a facility within the applicable segment, as defined in 40 CFR Part 98 at the time of passage of the bill.

Unless EPA proposes updates to facility definitions in 98.238, reporting should remain at the basin-level. Even if EPA were to propose new facility-level definitions in a future rulemaking, there are remaining concerns discussed below.

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[2] 88 Fed. Reg. at 50309.
[3] *Id*.
[4] *Id*.
[5] *Id.* at 50309-10.
[6] 88 Fed. Reg. at 50285.
[7] CAA § 136(c), (e).

EPA's justification for the proposed sub-facility-level reporting requirements is fundamentally flawed because the Agency wholly fails to consider whether the proposed requirements will be adequate to support applicability and fee determinations under the WEC. As noted above, EPA asserts that the new sub-facility-level reporting requirements are needed because the current Subpart W approach "can present challenges in the process of emissions verification, with corresponding potential impacts on data quality, and it also limits data transparency."[8] These reasons have nothing to do with the primary purpose of this rulemaking – to satisfy the Agency's obligation to revise Subpart W to provide sufficient information for implementation of the WEC.[9] Although not related to the WEC, in EPA's Response to Comments in 2009, EPA agreed that oil and natural gas is to be reported at the "upstream" level because further disaggregation would be burdensome to the reporter.[10]

In fact, nowhere in the Proposed Rule does EPA acknowledge that a key driver (if not <u>the</u> key driver) of the proposal is to generate the facility-specific data needed to implement the WEC, nor does EPA provide any analysis or assessment as to whether the new proposed sub-facility-level reporting requirements will be sufficient for that purpose. Unless corrected in a supplemental proposal, that failure to acknowledge and assess a key factor in the rulemaking will render the final rule arbitrary and capricious. *See*, *e.g.*, *Motor Vehicle Mfrs. Assn. of the United States v. State Farm Mut. Automobile Ins. Co.*, 463 U.S. 29, 43 (1983) ("Normally, an agency rule would be arbitrary and capricious if the agency has … entirely failed to consider an important aspect of the problem.") The WEC is based on the existing definitions of facilities subject to Subpart W; for that reason, there is no statutory basis to require reporting on a sub-facility-level basis. Basin-level data satisfies the Agency's obligation to revise Subpart W to provide sufficient information for implementation of the WEC.

EPA does not explain how the direction in CAA§136(h) in conjunction with CAA § 114 provides authority for EPA to develop extensive requirements in order to collect empirical data.

The text of CAA §136(h) provides:

> (h) REPORTING.—Not later than 2 years after the date of enactment…the Administrator shall revise the requirements of subpart W of part 98 of title 40, Code of Federal Regulations, to ensure the reporting under such subpart, and calculation of charges under subsections (e) and (f) of this section, are based on empirical data, including data collected pursuant to subsection (a)(4), accurately reflect the total methane emissions and waste emissions from the applicable facilities, and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, to demonstrate the extent to which a charge under subsection (c) is owed.

Thus, EPA is charged with updating Subpart W reporting to allow for the use of empirical data in reporting methane emissions that will ultimately become the emissions input to calculating the WEC. EPA does not explain in the Proposed Rule how this new congressional direction, layered on top of CAA § 114, provides authority for EPA to develop extensive requirements for installation of monitoring

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[8] I*d.* at 50309.

[9] CAA § 136(h).

[10] ". . . oil and other petroleum products must be reported by refineries, importers, and exporters under Subpart MM. For the proposed rule, EPA decided to require reporting at these points because reporting at natural gas and oil production wells would have been too burdensome and would have resulted in too many reporting facilities, with no improvement in data accuracy.", https://www.regulations.gov/document/EPA-HQ-OAR-2008-0508-2256.

equipment or sampling to acquire empirical data. In the preamble to this Proposed Rule, EPA failed to discuss its definition of empirical data or its views on what costs for implementation would be reasonable for collecting information under the program. Furthermore, in the discussion of new requirements for individual sources under Subpart W, EPA fails to discuss why individual changes are needed to provide empirical data for the purposes of calculating the methane fee. Before issuing a final rule, EPA must provide a thorough discussion of how this limited change to its statutory authority in the IRA provides a basis for these extensive revisions.

Reporting requirements under Subpart W must be reconsidered in light of the role that Subpart W will play in implementing the Waste Emissions Charge Program.

As noted above, key elements of the Proposed Rule are not adequately explained or supported because EPA failed to assess or explain how the proposed new reporting requirements square with the various elements of the WEC. A fundamental aspect of this issue is the fact that the information generated under Subpart W will be used for wholly different purposes under the WEC than it previously was under Subpart W alone. In particular, the emissions information reported under Subpart W will have new and significant legal ramifications because it will be used to determine the applicability of fee determinations under the WEC. So, Subpart W will be extended from a program that provides emissions data for informational purposes to support the development of the national Greenhouse Gas Inventory by EPA into a program that also serves as the compliance assurance component of the WEC. Simply put, this change in the rule now has financial implications for companies.

That expansion in the basic purpose of Subpart W is highly relevant to the Proposed Rule and in meeting EPA's obligation to revise Subpart W to "allow owners and operators of affected facilities … to demonstrate the extent to which a charge under subsection (c) is owed."[11] For example, as explained above, the extent to which "other large release events" should be reported under Subpart W must be established with an eye toward the relevance of the reported information in assessing the applicability and substantive requirements under the WEC program. The same is true of the other "gaps" in Subpart W that EPA proposes to fill in the Proposed Rule.

The rule must also allow an option to use directly or representatively measured data under all sources to demonstrate reductions in emissions. As proposed, not all source categories allow the use of directly measured data to demonstrate true reductions and improvements (i.e., flare combustion efficiency, crankcase venting, and any other area in the rule where reporters are required to use emission factors instead of having the option to directly measure).

Also, emissions information from oil and gas operations is developed to satisfy a wide range of regulatory and non-regulatory obligations beyond the WEC – including to show compliance with the NSPSs and NESHAPs for such operations and to satisfy emissions reporting obligations (e.g., the SEC's proposed disclosure rule). EPA must clearly specify the information needed to implement the WEC and prevent collateral challenges to WEC compliance based on information generated for other purposes under other regulatory programs.

In short, Subpart W is now unique among the GHGRP subparts in that emissions information submitted under Subpart W will serve regulatory purposes not shared by other industries that report under other

[11] *Id.*

subparts. As a result, EPA now must consider the implications under the WEC program of all Subpart W requirements and explain how Subpart W and the WEC will be integrated into a consistent, coherent, and workable program. EPA's failure to do so in the Proposed Rule constitutes a failure to consider a highly important aspect of the proposal and prevents interested parties from fully understanding, assessing, and commenting on the proposal.

2. 40 CFR Part 98, Subpart A

2.1 Transferred Assets

A new owner/operator should not be responsible for correcting or resubmitting reports submitted and certified prior to the date of acquisition of a reporting facility.

The Industry Trades acknowledge that EPA has attempted to address concerns over the requirement for a new owner/operator of a reporting facility to be responsible for historical GHGRP reporting prior to the facility's acquisition date by proposing assignment of a "Historical Reporting Representative."

The Industry Trades reiterate concerns highlighted in our October 6, 2022, letter[12] that a new owner/operator should not be responsible for correcting or resubmitting reports submitted and certified prior to the date of acquisition of any reporting facility. There are several complicated factors that EPA has not addressed as part of this rulemaking.

Proposing a "Historical Reporting Representative" does not guarantee the accuracy of historically reported information. First, there remains no guarantee that the selected representative would maintain access to the critical data systems used to generate the information used for historical GHG reports; once an acquisition is complete, those historical data systems are often no longer accessible by the purchaser (and in some cases, no longer maintained by the seller). While the "Historical Reporting Representative" could provide some anecdotal context around previously submitted reports, there is no guarantee that the "Historical Reporting Representative" would have had "primary responsibility for obtaining the historical information" which would not meet the threshold required for certification from a Designated Representative.[13] This is particularly true when assets are acquired from economically distressed companies which might no longer have any personnel who were involved in any of the historical GHG reports still on staff.

Furthermore, EPA has requested updates to previously submitted reports dating back 5 years and beyond; in many instances, the requested updates do not impact reported emissions and are often simply requests for clarification on certain reporting elements which are solely administrative in nature (e.g., a rolled up total of "Producing" wells in Table AA.1.ii does not match the count of wells labeled

[12] API Comments to EPA October 6, 2022. https://www.regulations.gov/comment/EPA-HQ-OAR-2019-0424-0322

[13] 40 CFR 98.4(e)(1): Each such submission shall include the following certification statement signed by the designated representative or any alternate designated representative: "I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

"Producing" in Table AA.1.iii). New owners or operators should not be required to update or submit reports for administrative issues which do not impact reported emissions, and EPA should limit the timeframe under which they request additional information or request re-submittals (see Section 2.2, 'Addressing "Substantive" Errors in a Methane-Fee Environment' below).

Currently within EPA's E-GGRT system, there is no way for a new company to access the reports that were previously submitted by the previous owner. Many times when files are transferred, files are missed or it is not clear what was actually submitted by the company. The new owner may not have access to the previous 5 years of submittals and will likely not have access to all the supporting historical records required to generate the report.

The Industry Trades are recommending that EPA require new owners to be responsible for resubmitting or correcting reports only after the point of acquisition, which is further addressed in the below section, 'Addressing "Substantive" Errors in a Methane-Fee Environment.'

2.2 Addressing "Substantive" Errors in a Methane-Fee Environment

A de-minimis threshold and timeframe must be established for errors to be considered substantive.

The Industry Trades reiterate our October 2022 comment that a threshold must be developed by which an error is to be considered substantive. As currently codified, the definition of "Substantive Error" is overly broad; any change, including those that are administrative in nature that do not impact methane emissions, could trigger a re-submittal. Since it is likely that future rulemaking will result in operators paying a methane fee on emissions, it will become increasingly critical for EPA to:

1. Determine a de-minimis "substantive error" threshold for methane emissions that excludes administrative errors that would result in a re-submittal;
2. Limit the timeframe in which EPA can determine that a "substantive error" has occurred; and
3. Limit EPA's validation of re-submitted reports to only the initial potential error.

As methane fees become associated with submitted reports, it will become extremely burdensome to adjust previously submitted payments for changes in a report which could result in very small financial adjustments. Furthermore, as reported emissions result in more financial impacts, the required levels of burdensome review for a change in reported data will increase, even if a change does not result in a change in emissions. For these reasons, Industry Trades are recommending that EPA develop a de minimis threshold for "substantive errors" of 5% of an applicable facility's reported methane emissions. This 5% de minimis threshold for total GHG emissions is aligned with a level of emissions change that many companies use for updating their corporate emissions due to errors and/or acquisitions/divestitures in accordance with the WRI/WBCSD GHG Protocol. While EPA may not know the scope of a possible error when initially requesting additional information, the reporter should have the option to not re-submit the report if an error is found to be below the de minimis threshold, and operators can provide the supporting information in their response to EPA through E-GGRT.

Finally, the Industry Trades are recommending a limit to the timeframe in which EPA can determine that a substantive error has occurred. The Industry Trades recommend that EPA limit the timeframe in which a "substantive error" can result in a requirement to resubmit a prior year's report to no more than three years, consistent with the record retention requirement in 40 CFR 98.3(g). Further, for re-submittals, EPA should limit the validation to the requested source(s) for which the substantive error was identified. This will avoid the burden of the current practice of EPA re-opening inquiries for other sources that previously have already been addressed by the reporter. This still allows EPA plenty of time for review and questions.

3. 40 CFR Part 98, Subpart W

3.1 Pneumatic Devices

Given the proposed zero-emitting standard in NSPS OOOOb and EG OOOOc, EPA should alleviate the burden with measuring and monitoring emissions across the proposed methodologies from natural gas driven pneumatic controllers during their transitional phase out in upcoming years.

Under NSPS OOOOb and EG OOOOc (§60.5390b and §60.5394c), EPA has proposed a zero-emitting standard for natural gas driven pneumatic controllers that, if finalized as proposed, will result in the elimination of methane venting from natural gas driven pneumatic devices, with the exception of those located in Alaska at a site without power. As part of separate comments on the EPA proposed NSPS OOOOb and EG OOOOc, several of the Industry Trades recommended there be limited exceptions to the zero-emitting standard where not feasible and to use the leak detection and repair program monitoring to confirm proper functioning of pneumatic controllers EPA should consider the requirements and timelines that it is proposing across NSPS OOOOb, EG OOOOc, and Subpart W to promote efficiency across the programs and focus on emission reductions.

Given the potential changes to pneumatics under OOOOb and OOOOc, the time period and practicality of using several of the proposed methods for Subpart W may be minimal. As proposed, Method 1 in §98.233(a)(1) requires installation of permanent flowmeters on equipment that will eventually be removed from service. As proposed, Method 2 would require direct measurements on all natural gas driven pneumatic devices over a several year period that corresponds to expected timelines under NSPS OOOOb and EG OOOOc. Method 2 would require purchasing new measurement equipment and training technicians on their operation, which would have a limited window of use with timelines in NSPS OOOOb and EG OOOOc.

Based on the complexities noted above, Method 3 will likely be utilized by many operators for Subpart W reporting. While the Industry Trades support the intent of proposed Method 3, this option also currently includes undue burden for estimating emissions from devices that will, for the majority, not be in operation within the next decade.

Therefore, the Industry Trades offer the following recommendations, which we describe in more detail in the following comments:

- For natural gas driven pneumatic controllers that are not measured under Method 1 or Method 2 or monitored for proper function under Method 3, EPA should allow the use of the single whole gas population emission factor for intermittent-bleed devices (refer to Section 3.1.1).
- EPA should allow an optional estimation of properly operating intermittent-bleed pneumatic controllers using equipment-specific engineering calculations, or a facility-specific properly operating emission factor based on direct measurement. We elaborate on the details further in Section 3.1.3.
- Amend the proper functioning and malfunctioning emission factors for intermittent-bleed devices to include all relevant studies (refer to Section 3.1.3).

- Allow the duration of an intermittent-bleed device malfunction to be determined by repair date or the last monitoring survey (refer to Section 3.1.4).

Note that both Method 2 and 3 provide time horizons for conducting flow measurements or monitoring surveys up to a 5-year cycle depending on the industry segment in which a facility is located. For both onshore production and gathering and boosting, EPA has proposed that operators measure/monitor approximately the same number of devices each year. This timing directly coincides with the implementation of NSPS OOOOb/EG OOOOc and complicates how an operator might track monitoring or measurement results as equipment changes at a facility. Over time, it may be impossible to monitor the same count year-over-year as the total count of natural gas driven devices will reduce over time.

3.1.1 Retain Whole Gas Emission Factor Approach for Intermittent-Bleed Devices

While operators should have the *option* to measure and monitor emissions from those devices, it should not be *required* for sources expected to be phased out as required in other regulatory programs, as this would result in undue capital investment without creating additional value to stakeholders. The proposed methods are highly inefficient and unnecessary considering the required 15-minute measurement time per device or monitoring each device (i.e., OGI or Method 21 screening) for 2 minutes or until a malfunction is identified. The additional burden is not justified considering:

- Any accuracy gain is expected to be temporary considering that proposed federal air quality rules require all pneumatic devices to be transitioned to zero emitting devices;
- Continuous bleed pneumatic devices, a higher emitting source, are allowed to report using an emission factor approach; and
- It penalizes operators who have invested in cleaner technology by replacing continuous high-bleed controllers with intermittent-bleed devices by requiring them to be measured or monitored.

Therefore, **EPA should retain the option to use the default whole gas population emission factor for intermittent bleed pneumatic devices,** as has been proposed under Method 3 for both continuous high- and low-bleed pneumatic devices. Consistent with the derivations used for new emission factors for high and low bleed continuous pneumatic controllers in Table 5-11 of the Technical Support Document for this Rule, EPA suggests the use of 8.8 scf/hr./device for intermittent bleed pneumatic devices, based on a meta-analysis of a variety of field studies. Moreover, many operators are actively working toward voluntarily eliminating most of these sources as they either fall under current or anticipated upcoming state or federal regulations requiring either source control or a zero emissions standard for this equipment. Implementing a burdensome monitoring program for sources that will soon become less significant doesn't make sense. Operators have collectively performed thousands of retrofits to convert continuous high-bleed pneumatic devices into intermittent bleed devices. Operators who acted swiftly should not face more burdensome greenhouse gas accounting requirements, nor should further near-term retrofits be discouraged by imposing disproportionate accounting burdens.

3.1.2 Method 2 – Suggest Improvement in Measurement Cycle and Alternative Approach

The Industry Trades generally support EPA's Calculation Method 2 to distribute measurement campaigns over multiple years where flow monitors are not permanently installed, with the following amendments:

1) Since the as-proposed NSPS OOOOb and EG OOOOc require phase out of this equipment and numerous operators have been reducing these equipment counts voluntarily, it is not possible to

monitor the same number of controllers each year since equipment counts will be simultaneously declining. Instead, **EPA should require the annual inspections to cover at least 20% of the population of pneumatic controllers at a facility** that have not already been inspected pursuant to Subpart W within the previous 4 years, provided that each device remaining in service at the end of the first five years has received at least one inspection over the five-year period.

2) Additionally, EPA should allow operators to **directly measure a representative sample of pneumatic devices in lieu of the entire population.** This approach ensures accuracy of reported emissions but recognizes the vast geographic dispersion of upstream sites. Additionally, API performed a study on the count of pneumatics at upstream sites and provided that in comments regarding the supplemental OOOOb rulemaking.[14] The time required to drive to each site would be unnecessary when a smaller, representative sample accurately reflects the emissions from these devices. Lastly, this approach is incorporated in several voluntary programs (e.g., OGMP 2.0), retains the accuracy of reported emissions, considers the large geographic dispersion of upstream sites, is consistent with the approach proposed for equipment leaks, improves accuracy over generic emission factor-based estimates, and is more cost effective. The representative emission factor approach would require measurement of a representative sample of pneumatic devices to determine a "facility" specific emission factor.

3.1.3 Method 3 – Suggested Amendments to Improve Intermittent-Bleed Device Monitoring

The Industry Trades also generally support EPA's Calculation Method 3; however, **EPA should amend Calculation Method 3 in three important ways**:

1) **EPA should allow the use of a whole gas emission factor as an option for intermittent-bleed devices,** for the reasons stated in Section 3.1.1**.**
2) **EPA should amend Equation W-1C to more accurately reflect available empirical data on emissions from properly functioning pneumatic controllers**, including a broader suite of field data to improve accuracy. Emission factors should incorporate data from additional relevant studies, [15,16,17] one of which is the API Study "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States," where the data and results have been appended to this letter in Annex A. We encourage EPA to utilize the data from this API study, since the API dataset adds 263 additional measurements of intermittent bleed controllers and cover a wide cross section of the industry sectors (production and gathering and boosting sites)[18]

[14] https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428.

[15] Raw data and linked analyses/reports available at http://dept.ceer.utexas.edu/methane/study/. Accessed September 24, 2023.

[16] David T. Allen, Adam P. Pacsi, David W. Sullivan, Daniel Zavala-Araiza, Matthew Harrison, Kindal Keen, Matthew P. Fraser, A. Daniel Hill, Robert F. Sawyer, and John H. Seinfeld. *Environmental Science & Technology* 2015 *49* (1), 633-640. DOI: 10.1021/es5040156

[17] API Study "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States" attached in Annex A and data provided by attachment as an Excel file within this docket.

[18] Note that EPA's comment in the TSD regarding being near or below the OGI threshold for properly functioning controllers using the API field study's emission factor would be resolved by combining the Zimmerle, API, and other relevant datasets to derive properly functioning and malfunctioning emission factors as shown below in Revised Eq. W-1C (the proposed properly functioning emission factor of 0.9 scf/hr/device is equivalent to ~17 g/hr, which is

while the Zimmerle *et al* study only evaluated sites with compression; thus, the resulting bifurcated emission factors would be more accurate and representative. Specifically, **the Industry Trades recommend revision of Eq. W-1C:**[19]

$$E_i = GHG_i \times \left[\sum_{z=1}^{x}\{\mathbf{20.0} \times T_{mal,z} + \mathbf{0.9} \times (T_{t,z} - T_{mal,z})\} + (\mathbf{0.9} \times Count \times T_{avg})\right] \; (Rev.Eq.W-1C)$$

Where:

20.0 = Whole gas emission factor for properly functioning intermittent-bleed controllers, scf/hr.

0.9 = Whole gas emission factor for malfunctioning intermittent-bleed controllers, scf/hr.

3) **EPA should allow for the optional estimation of properly operating pneumatic controllers based on equipment specific engineering calculations**, which can be accurately assessed with piping volume, manufacturer actuation data, and average actuation frequency,[20] **or the development of a facility specific properly operating emission factor through direct measurement** of a representative sample of devices across a facility.

$$E_i = GHG_i \times \left[\sum_{z=1}^{x}\{16.1 \times T_{mal,z} + EF_z \times (T_{t,z} - T_{mal,z})\} + \sum_{y=1}^{y}\{EF_y \times T_{t,y}\}\right]$$

Where:

z = Count of intermittent bleed pneumatic devices that malfunctioned during the reporting period,

y = Count of intermittent pneumatic devices that properly operated over the entire duration of the reporting period, and

EF = Properly operating emission factor for the specific device or facility.

3.1.4 Intermittent-Bleed Device Survey Improvements

The duration of an intermittent bleed device malfunction should be determined by repair date or other detection approaches, in addition to traditional survey repair verifications.

Operators will have a clear indicator that a malfunctioning device has been returned to properly operating condition based upon the repair date or other detection approaches. EPA should allow for such information to be used for the time input into the malfunctioning controller emission estimation equation, which aligns with EPA's efforts to increase the quality / accuracy of the reported data. For

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above the OGI detection limit). EPA also speculates in the TSD that the API field study included many zero emitting measurements due to the short measurement duration. However, as discussed in the attached paper (see Annex A, pp. 4), the measured emission data points that were below half the effective resolution were conservatively assumed to be half the effective resolution for the minimum instantaneous emission rate in all the analyses. Further, the Allen *et al* 2014 paper conducted a sensitivity analysis which showed that actuations that were just missed by the measurement timeline at 15 minutes had a very small effect on the overall population emission factor estimate.

[19] See Annex F Analysis to support amendment to Calculation 3 for Intermittent Bleed Devices.

[20] https://ogmpartnership.com/wp-content/uploads/2023/02/Pneumatics-TGD-SG-approved.pdf.

example, while conducting AVO inspections, operators can detect that an intermittent device is continuously venting by feeling the gas exit port.

The Industry Trades also support EPA's proposal to retain the option for an operator to apply engineering estimates to determine the time in which the device was in service, in lieu of the default 8760 hours.

Intermittent bleed device surveys should include additional flexibility by allowing audio, visual, and olfactory (AVO) inspections.

Operators should be able to take credit for any surveys, provided those surveys satisfy the intent of the rule. Based on the proposed rule for NSPS OOOOb, facilities subject to NSPS OOOOb monitoring would be required to use non-emitting pneumatic devices. Some facilities that are not subject to NSPS OOOOb may conduct LDAR for state, federal, or voluntary programs and may wish to screen pneumatic controllers while on-site and use that empirical observation of properly functioning or malfunctioning for GHGRP reporting.

While many of these regulatory programs would meet the technology options provided in 98.234(a) for use in monitoring properly functioning pneumatic devices, additional flexibility should be incorporated by allowing the use of AVO. AVO is appropriate because AVO inspections can be used to detect that an intermittent device is continuously venting through feeling the gas exit port, as previously stated.

3.1.5 EPA Has Underestimated the Cost of Direct Measurement for Pneumatic Devices

Oil and gas companies do not currently own or have training to conduct direct measurement of pneumatic devices. EPA included no additional cost for purchasing the high flow sampling equipment, staff or training on the equipment. With the large number of operators having to acquire this data at the same time, new equipment must be first manufactured and then purchased by these operators to do this work concurrently. EPA added no additional labor impact; it will require significantly more staff to conduct the measurements. The company will need to hire staff, as additional staff will be needed to conduct these measurements that require 15 minutes per measurement minimum over a range of device counts per facility depending on whether it is a gas or oil well, number of wells, and the equipment required for production. It will likely not be possible to cover 5-10 sites per day, considering repairs will likely be performed at the same time and many sites and pneumatic devices will be spread out over long distances. Furthermore, operators will need to be trained to use high flow samplers as this equipment is currently not used in the oil and gas industry. None of these additional costs have been addressed in the Regulatory Impact Analysis. EPA claimed all this could be done with only an additional $600,714 in cost which would not be sufficient to cover the cost for a medium sized operator.

3.2 Acid Gas Removal and Nitrogen Removal Units

3.2.1 Proposed Methods for Methane Emissions

The proposed mass balance approach for quantifying emissions will not lead to accurate reporting for methane emissions, and sour gas sampling poses a significant safety concern.

EPA proposes to report methane along with CO_2 from Acid Gas Removal Units (AGRUs) and Nitrogen Removal Units (NRUs). The Industry Trades believe that the proposed methodology in Equation W-4C (a mass balance approach) will not lead to accurate reporting for methane emissions. Since the solubility of methane in amine is very low, the difference in methane concentration in the inlet and outlet processed gas stream will be negligible. Therefore, the ability to discern a difference in inlet versus outlet methane composition will make it difficult (if not impossible) to accurately determine methane emissions using a mass balance approach. Further, sampling the high-pressure acid gas stream at the inlet of the AGRU contactor poses a significant safety concern (see next comment). For these reasons, the Industry Trades recommend removing this methodology for methane emissions reporting.

EPA is proposing a requirement to perform direct sampling of gas streams into these units at least annually. The Industry Trades remind EPA that these streams can also contain dangerous levels of hydrogen sulfide (H_2S), and any work near or around these units that is not necessary for the optimal function of the equipment should be limited to protect the personnel responsible for performing these tasks. The Industry Trades recommend removing the prescriptive sampling requirements for these streams and allow reporters to use representative samples or direct site-specific samples if deemed to be appropriate.

For the simulation method (Method 4), the Industry Trades recommend that EPA clarify that representative measurements can be one time, annual or a more frequent measurement as deemed appropriate for the facility's operation.

3.2.2 Reporting Requirements for AGRUs and NRUs

Some of the proposed reporting requirements for AGRUs and NRUs are duplicative and unnecessary, so should be removed.

EPA proposes that those operators sending gas from an AGRU or NRU to a control device also report associated details regarding the combustion device (flare ID, gas flow rate, etc.). Requiring this information to be reported on this tab of the Subpart W reporting form could cause duplicative reporting with sources on other tabs (e.g., flares), and is ultimately not relevant to reporting by itself. The Industry Trades recommend removing this requirement. Reporting this level of detail is also inconsistent with EPA's 2022 proposed revisions, which greatly streamlined the reporting requirements for flares.

EPA is proposing to include solvent type in data reporting; the Industry Trades does not believe this information to be beneficial or helpful in validating the reported information, and EPA did not address why this element is to be reported in the TSD. The Industry Trades recommend that the EPA remove this unnecessary reporting requirement.

Finally, the Industry Trades request clarity from EPA around reporting activities such as acid gas injection through Subparts W, PP and UU. The proposed requirement to report CO_2 sent offsite under Subpart PP is duplicative of CO_2 supplier reporting. Regarding the WEC, it will be absolutely critical that industry has a clear understanding of exactly how emissions are to be accounted for between these subparts without over-reporting, double counting, or allowing some operators to not report under these subparts at all (creating an economic disadvantage as it is unclear how some activities which result in producing CO_2 are to be accounted for in the various rules).

3.3 Dehydrators

3.3.1 Desiccant Dehydrators

Reporting requirements for desiccant dehydrators should be streamlined for a source type that is not a significant contributor to GHG emissions.

In the late-2022 proposed changes, EPA appeared to be moving away from requiring detailed information reported for desiccant dehydrators; however, in the current proposal (August 1st, 2023), EPA is requiring more reporting details. Emissions from desiccant dehydrators are periodic and can be very infrequent in nature. The Industry Trades support reducing the overall reporting requirements on these units as they are not significant contributors to annual GHG emissions.

Molecular sieve dehydrator emissions are expected to be extremely infrequent (i.e., once every 5-10 years), and should be categorized as blowdown emissions.

EPA is also proposing to add molecular sieve units to the desiccant dehydrator category. Molecular sieves are closed systems with no emissions to the atmosphere, except when the desiccant must be changed which is infrequent; typically, only once every 5-10 years. Furthermore, emissions from opening a molecular sieve dehydrator would be an activity considered by most operators to be a blowdown event – and should be accounted for under the blowdown category rather than under dehydrators. Categorizing molecular sieves under the desiccant dehydrator category not only raises confusion but could potentially result in double counting of the blowdown emissions.

3.3.2 Proposed Measurement Data

The proposed measurement requirements are burdensome and will not increase the accuracy of the emissions estimates; therefore, engineering estimates for parameters should be allowed.

EPA is proposing to require direct measurement of some parameters for large dehydrators. Specifically, EPA is proposing to require direct measurement of the feed natural gas flow rate, feed natural gas water content, and wet natural gas temperature and pressure at the absorber inlet. The Industry Trades do not believe that direct measurement of these parameters is appropriate nor that it would result in more accurately reported emissions. Sampling the feed natural gas water content, gas temperature and pressure will provide an instantaneous snapshot view of the operational conditions of a unit that operates year-round, and in potentially varying operating conditions, during which these parameters may shift.

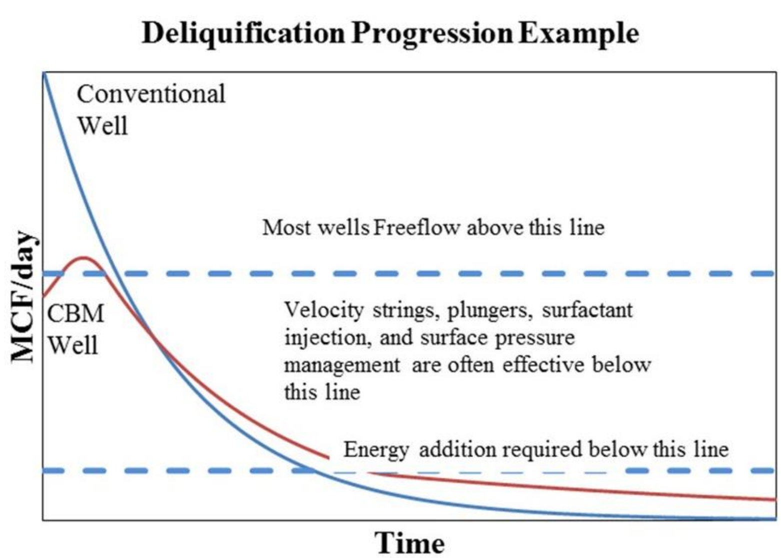
In some instances, facilities are not equipped with a meter upstream of the dehydration unit; instead, the gas is measured at the outlet of the facility. As a result, collecting direct measurement of feed natural gas flowrate will require extensive modifications without increasing the quality of the reported data. Dehydrator emissions are not directly proportional to natural gas throughput; in other words, the inlet gas rate to the dehydrator alone does not correlate with dehydrator emissions. Instead, glycol recirculation pump rate, configuration (e.g., flash tank separator, stripping gas) and operating pressures do impact emissions, and are known by operations in order to maintain optimum operating conditions. Requiring operators to install, calibrate and maintain meters at the inlet to the dehydrators would be costly while not addressing the accuracy of the elements that do meaningfully impact actual emissions. Therefore, the Industry Trades request that engineering estimates of the parameters used in the simulation software continue to be included as an option, especially considering the parameters represent annual averages.

3.4 Well Venting for Liquids Unloading

EPA should not require flow meter measurements of liquids unloading venting under Calculation Method 1 as it is technically and economically infeasible.

The proposed rule language that requires Calculation Method 1 every three years is unnecessary and burdensome and will not lead to more accurate reporting. EPA states in the preamble that this requirement will 'ensure that the engineering equations accurately and consistently represent the quantity of emissions from unloading event.' EPA must justify this additional burden and how potential differences between method results will be treated, as repeated validation of the methods will not lead to more accurate reporting. Further, EPA did not consider the Allen *et al* 2015 study that directly measured emissions from liquids unloading.[21]

Which wells will require and how often they require liquids unloading venting is not predictable or consistent. Liquids unloading or deliquification is the process of removing liquids build-up in a gas well. Not all deliquification techniques result in venting. Most wells in the US do not vent to the atmosphere. Managing well bore liquids build-up in gas wells is required to maintain production, avoid early abandonment of the wells, and maximize resource recovery. Liquids build up in the well when the velocity of the production string is not sufficient to push the liquids up the well bore. The deliquification approaches change as a well moves through its lifecycle, as shown in the figure below. Manually opening a well to atmosphere to reduce the back pressure on the liquids column results in most of the liquids unloading venting. When this is needed is variable and does not necessarily occur every 3 years.



[21] https://pubs.acs.org/doi/10.1021/es504016r.

Adding a flow meter will put back pressure on the well, restricting flow and preventing the well from unloading or making it more difficult. The purpose of liquids unloading is to relieve the back pressure on the well so that the well is able to push liquids, and a flow meter would prevent this from occurring. Anecdotal evidence from one operator that currently unloads gas wells in Colorado has trialed measurement on liquids unloading on twelve wells indicating this. The operator found results similar to the current GHGRP calculations. Additionally, the operator found that to use a meter, the gas must be routed through a knockout or other vessel that may have small piping between it and the meter. The constriction made the unloads take longer and reduced the effectiveness of the unloads. Of the twelve trial measurements, not a single well successfully unloaded itself.

The volume of gas, and associated GHG emissions, is relatively low and therefore does not warrant the additional expense and effort of measurement. In fact, the total emissions reported in 2021 for all operators was a very small percentage of overall methane emissions from onshore production.

Measuring the small volume will be extremely challenging and likely require a costly ultrasonic meter (please see the flow meter challenges discussed in more detail in Section 3.8.13.8.1 of the comments). The measurements will be challenging to obtain, as they are short duration and turbulent flow; therefore, the low flow is unlikely to be measured by a flow meter.

The rule does not account for all the added costs of a flow meter that will likely not be capable of measuring the small volume of the gas. These costs include:

- The flow meter(s)
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofit the line to add a flow meter
- Expanding or adding the remote facility computer (remote oil field controller)
- Expanding or adding data storage capacity on site
- Wiring to the remote facility computer
- Expanding or adding the remote transmitting unit
- Calibration and maintenance of the flow meter
- SCADA and alarm programming
- Data management system
- Data review and analytics
- Data entry for calculations

Additionally, EPA does not require operators under NSPS OOOOb to install a flow meter for liquids unloading venting. NSPS OOOOb does not prescribe these flow meter requirements as necessary to achieve the zero-emission limit for liquids unloading, or for the recordkeeping/reporting requirements for these events, so it is unclear why this would be required under Subpart W.

Furthermore, a meter could be installed on a well that had liquids unloading venting in a previous year and never does again, or not be installed on a well that suddenly requires liquids unloading venting.

Industry should be allowed to continue to use the liquid unloading engineering estimates or other engineering process knowledge to estimate the duration and volume of emissions as measurement will not result in more accurate estimates.

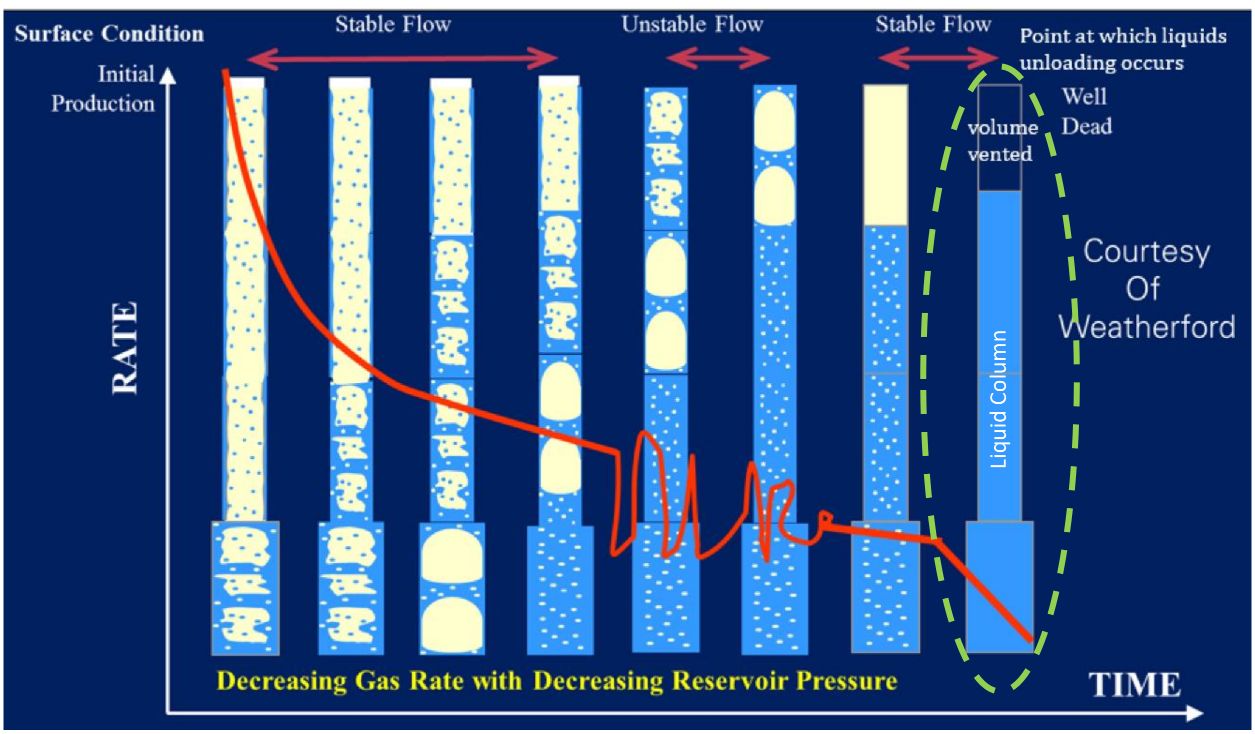
Additional suggested revisions will improve the clarity of the requirements for reporters.

EPA should clarify that liquids unloading only applies to gas wells as was done in NSPS OOOOb. Oil wells typically require artificial lift to produce the liquids and do not vent gas.

The Industry Trades support proposed revisions to add reporting requirements for liquids unloading events which vent directly to atmosphere or are routed to a control device, including whether the unloading event is automatic or manual, specific flow-line and tubing depth data, and the hours that wells are left open during unloading events. However, EPA should clarify that reporting for unloading events should only apply when the gas is vented directly to the atmosphere or routed to a control device. These additions will improve clarity for reporters and provide greater context for the reported emissions for EPA.

Additionally, EPA should consider revising the definition of CDp in Equation W-8 to Idp (Internal Diameter) to allow the application of either tubing diameter if the well is equipped with tubing string and no plunger lift, or casing diameter if the well does not have tubing and plunger lift. It is common practice for operators to first install a tubing string to increase flow velocity and install a plunger lift later when the well undergoes production decline. The diameter that is used in the equation should be the diameter of the portion of the well that is vented, whether venting the casing, tubing, or both. EPA should also clarify that the depth is based only on the vertical depth for horizontal wells.

Furthermore, the volume should be able to account for the fluid column depth. EPA should allow companies to determine the depth to the top of the fluid and exclude the remaining volume from the venting volume estimate. The reason for liquids unloading is to remove the liquid column from the well. The volume of liquid should not be considered gas that is vented, and rather only the depth above the fluids should be used to quantify the vented gas, as shown by the 'volume vented' in the following diagram.



3.5 Blowdowns

Streamline blowdown reporting to reduce the burden without affecting accuracy.

EPA is proposing to require site-level details regarding blowdowns. The Industry Trades recommend streamlining this source category by allowing reporters to aggregate events by type at each facility. Aggregating events by type would avoid line-by-line reporting per event and greatly reduce the complexity of reporting for the source category, without impacting data quality or transparency. For example, EPA should allow blowdown emissions to be reported by site, but aggregated by activity (i.e., all blowdown types would be reported in aggregate rather than line-by-line for each blowdown event).

For mid-field pipeline blowdowns not associated with a given well pad or gathering station, reporting a site could be challenging. The Industry Trades recommend allowing these types of blowdown events to be aggregated by county (without segment ID), which is consistent with other pipeline reporting under the current rules for Pipeline and Hazardous Materials Safety Administration (PHMSA).

As discussed in the 'Other Large Release Events' comments, there is a significant probability of double counting between blowdowns and 'Other Large Release Events' due to the low emission rate threshold proposed for the 'other large release events' source.

The Industry Trades are also concerned that, due to the low hourly emission rate threshold specified by EPA for the "Other Large Release Events" category, these events could be inadvertently counted in both this blowdown category as well as "Other Large Release Events" - resulting in significant double counting. EPA should clarify that any emission event that triggers the "Other Large Release Events" threshold but belongs under a reportable emissions source category (e.g., blowdowns) should be reported within its associated source category, not under "Other Large Release Events." The Industry Trades have elaborated on this point in the "Other Large Release Events" section of this letter.

3.6 Storage Tanks

3.6.1 Produced Water Tanks

Requiring estimation of emissions from produced water tanks is burdensome and unnecessary due to the low expected emissions of methane based on solubility limits.

Methane emissions from produced water tanks are expected to be low due to solubility limitations of methane in water. A study conducted by Idaho State University[22] to quantify the solubility of methane in produced water found that the solubility of methane was in a range between 1 and 12 scf/barrel at pressures ranging from around 100 to 2,000 psi and temperatures ranging from 200 to 300°F. While the study did not publish results for lower temperature ranges, the authors state that the solubility decreases with decreasing temperature and/or pressure. The solubility of methane in produced water is also expected to be lower in the presence of other hydrocarbon gases, such as ethane, per the study authors. The Idaho State University methane solubility study results are aligned with the produced water emission factors published in the 2021 API Compendium (Table 6-26): the Idaho State University study value at around 1000 psi, 200°F and 13 % salinity (4.2 scf/bbl.) equates to around 0.08 tonne CH_4/1,000 bbl which compares to 0.0536 tonne CH_4/1,000 bbl (at 1000 psi, 10% salinity) from Table 6-26 of the API Compendium. Since the methane emissions from a produced water tank would be lower than the

[22] Blount, C. *et al*, *Solubility of Methane in Water Under Natural Conditions*, Idaho State University Department of Geology, June 1982, https://www.osti.gov/servlets/purl/5281520.

solubility limit (i.e., emissions are based on the partial pressure of methane in the tank headspace, which is lowered when other hydrocarbons are present), the Idaho State University study corroborates the API Compendium emission factors for produced water tanks.

If EPA opts to keep produced water tanks in the GHGRP, the Industry Trades recommend allowing operators to assume that water tanks contain 1% of the oil content. Texas Commission on Environmental Quality (TCEQ) Emissions Representation for Produced Water guidance[23] describes that oil or condensate floats on top of the water phase and contributes to the partial pressure within the tank. The Industry Trades recommend that EPA allow operators to assume that 1% of the oil content is in the produced water tanks which is a conservative estimation given that the guidance is intended to capture VOC emissions, and it is unlikely (as described above) that significant methane remains in the produced water.

The Industry Trades note that EPA provides a stuck dump valve emission factor for water tanks if method 1 or 2 is used, but no factor is provided for tanks using method 3.

3.6.2 Thief Hatches

EPA should allow improperly seated thief hatches to be treated as an "other" component under equipment leaks. The proposed capture efficiency of zero percent for storage tanks with an improperly seated thief hatch is inaccurate and would significantly overestimate emissions.

EPA has proposed a 100 percent reduction in VRU capture efficiency and flare destruction efficiency for both hydrocarbon and produced water storage tanks with open and improperly seated thief hatches. This proposed reduction in capture efficiency is inaccurate and would significantly overestimate methane emissions. The Industry Trades propose a bifurcated approach to reporting emissions from thief hatches where improperly seated thief hatches would be treated as a fugitive emission reported under equipment leaks, and open thief hatches would result in a zero percent capture efficiency for control devices.

Thief hatches are safety devices that relieve positive and negative pressure in atmospheric storage tanks to prevent structural damage. Thief hatches accomplish this by using weights or springs that allow the thief hatch valve to open at given pressure and vacuum settings. The thief hatch valve then reseats after the tank pressure or vacuum has dissipated. Thief hatch valves are designed to seat with minimal leakage under their pressure setting. For example, Enardo 660s, a common thief hatch in the upstream oil and gas industry, conforms to API 2000 Venting Atmospheric and Low-Pressure Storage Tanks Standard to not leak more than 5 SCFH at 75-90% of the thief hatch valve's pressure setpoint. Many of Enardo's valves can achieve smaller leak rates at 90% of the pressure setpoint. LaMot's L12 series thief hatches, another common type found at upstream oil and gas facilities, will not leak more than 1 SCFH at 90% of the pressure setpoint. These leak rates are a fraction of the gas produced in tanks. For example, the reduction in capture efficiency ranges from 0.5% to 2.5% given these leak rates for tanks with a relatively small throughput of 100 bbl./day and average GOR of 48 scfs/bbl given the above leak rates. Improperly seated thief hatches are technically closed but leak around the seat due to either grime on the valve gasket or an inadequate seal, similar to valves that leak into open-ended lines. Improperly seated thief hatches do not result in a zero percent capture efficiency because they are still able to

[23] produced-water.pdf (texas.gov).

maintain positive pressure on the tanks, allowing gases to be routed to the control device. The leakage from an improperly seated thief hatch is significantly lower than from a partially open thief hatch.

EPA's proposal to assume zero percent capture efficiency from improperly seated thief hatches that are leaking as opposed to venting gas will grossly overstate methane emissions. Instead, the Industry Trades propose that improperly seated thief hatches be considered and reported as a fugitive emissions component (under the "other" fugitive component category).

A zero percent capture efficiency as proposed by EPA would be used for thief hatches that are observed above their setpoint using pressure transmitters and confirmed open or found open during inspections. The Industry Trades believe that this bifurcated approach of accounting for improperly seated thief hatches as equipment leaks, and assuming open thief hatches result in a zero percent capture efficiency would be a more accurate representation of emissions from thief hatches.

EPA should allow engineering estimates of the open thief hatch volumetric flow for tank batteries with a common vent line.

For many tank batteries, vent lines for multiple tanks are combined in a common vent line header that is routed to a control device. If one thief hatch is found open, the entire tank battery should not be assumed to have open thief hatches with a resultant zero percent capture efficiency. The Industry Trades suggest that EPA allow for use of engineering estimates, e.g., modeled volumes, in this case to report the emissions from the tank battery's open thief hatch.

EPA should allow other monitoring options to detect open thief hatches besides thief hatch sensors and visual inspections as visual inspections create significant safety concerns. The start date for an open thief hatch should be based on best available monitoring data.

EPA proposes thief hatch sensors or visual inspections as the monitoring options for detecting open thief hatches on controlled storage tanks. The Industry Trades recommend that EPA allows Tank Emission Monitoring Systems (TEMS) or other parametric monitoring in addition to thief hatch sensors. For example, many companies utilize a pressure transmitter or similar device to determine if a thief hatch is venting as they are more accurate.

Similarly, EPA should expand the visual inspections to allow other monitoring techniques (audio and olfactory in addition to visual, OGI, and alternative screening technology) due to potential safety issues with a strictly visual inspection of thief hatches. Since thief hatches are located on the top of the tanks, a visual inspection may require personnel to climb to the top of the tanks with potential vapor exposure (e.g., H_2S). Therefore, more remote monitoring techniques should be allowed to monitor for open thief hatches on controlled tanks.

Thief hatch sensors do periodically malfunction and may falsely indicate an open thief hatch. As such, EPA should allow reporters to exclude thief hatch sensor malfunction periods and instead use best available monitoring data (e.g., TEMS, other parametric monitoring, last inspection) when determining the time that the thief hatch was open in calculating and reporting storage tank emissions.

EPA is proposing that an open thief hatch without a thief hatch sensor is to be considered open since the last required inspection, which is proposed at least annually or more frequently if subject to AVO surveys under NSPS OOOOb or EG OOOOc. The Industry Trades recommend that EPA allow an operator to assume the thief hatch has been open since the last credible inspection (e.g., routine operator inspection) and not solely based on the last required thief hatch inspection. Proposed NSPS OOOOb and EG OOOOc (and earlier versions of the NSPS) do not require thief hatch sensors but instead require routine inspections of closed vent systems and covers for applicable storage vessels in addition to routine site surveys of fugitive emissions components. These inspections and additional monitoring would offer more frequent opportunities for operators to identify open thief hatches on a routine basis.

Emissions from an open thief hatch should be reported for the year in which it was discovered.

EPA is also seeking comment on expanding the start date of the open thief hatch prior to the beginning of the reporting year. The Industry Trades suggest that the reporting for an open thief hatch be limited to the calendar year in which the open thief hatch is discovered. If the thief hatch is open over a period that started prior to the start of the reporting year, then the total duration should be reported in the year in which it was discovered to avoid re-submittal of prior year reports. To expand on this point, the Industry Trades propose that any episodic GHG emissions be reported solely in the reporting year in which it was discovered.

3.6.3 Atmospheric Storage Tank Exclusions

The Industry Trades recommend that emergency use storage tanks and process tanks not be subject to reporting.

The Industry Trades also recommend that EPA specify that some tanks are not subject to reporting under this program. Some facilities contain tanks which are used only rarely for off spec oil and should be excluded from the definition of storage vessel. These process vessels are rated significantly higher than atmospheric and do not have similar venting risks as atmospheric storage tanks. The expected GHG emissions from these emergency use storage tanks would be minimal. At the state level, emergency use tanks are exempt from control requirements from state and local regulations because state agencies such as California's Air Resources Board (CARB) or San Joaquin Valley Air Pollution Control Board (SJVAPCD) have recognized that these tanks are used in rare and extreme situations for the safety of people and nearby infrastructure.[24,25]

Likewise, process tanks like those that recirculate liquids for processing should also be excluded. Storage tank regulations, including proposed NSPS OOOOb and EG OOOOc, have historically excluded process vessels or tanks. In short, any tank which is not expressly used as a primary storage vessel for hydrocarbon liquids and produced water (if included as proposed) in the normal operation of a production or gathering and boosting facility should be excluded. Therefore, the Industry Trades offer the following redline of the proposed definition of atmospheric pressure storage tank:

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[24] CARB O&G Regulation, 17 CCR 95668(a)(2)(E): Separators, tanks, and sumps that have contained crude oil, condensate, or produced water for 45 calendar days or fewer per calendar year provided that the owner or operator maintains, and can make available at the request of the ARB Executive Officer, a record of the number of days per year in which the separators, tanks, or sumps have contained liquid.

[25] The SJVAPCD has defined an emergency in some permits as: an unforeseeable failure or malfunction of operating equipment that: (1) is not due to neglect or disregard of air pollution laws or rules; (2) is not intentional or the result of negligence; (3) is not due to improper maintenance; and (4) is necessary to prevent or control an unsafe situation.

> *Atmospheric pressure storage tank means a vessel ~~(excluding sumps)~~ operating at atmospheric pressure that is designed to contain an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water and that is constructed entirely of nonearthen materials (e.g., wood, concrete, steel, plastic) that provide structural support. Atmospheric pressure storage tanks include both fixed roof tanks and floating roof tanks. Floating roof tanks include tanks with either an internal floating roof or an external floating roof. For the purposes of this subpart, the following are not considered atmospheric pressure storage tanks:*
>
> - *Sumps;*
> - *Process vessels such as surge control vessels, bottoms receivers or knockout vessels; and*
> - *Vessels that only receive crude oil, condensate, intermediate hydrocarbon liquids, or produced water due to an unforeseeable failure or malfunction of operating equipment that is necessary to prevent or control an unsafe situation and contains the crude oil, condensate, or produced water for 45 days or less per calendar year.*

3.6.4 Gas-liquid Separator Liquid Dump Valves

The start date for a stuck separator dump valve should be based on best available monitoring data.

Like the above comment on open thief hatch monitoring, EPA should allow the start date for a stuck gas-liquid separator liquid dump valve to be based on the best monitoring data available (TEMS, other parametric monitoring, alternative screening technology, routine operator inspections, etc.) rather than solely the date of the last required annual visual dump valve inspection. This flexibility will allow operators to calculate storage tank emissions more accurately.

3.6.5 Addressing EPA's Request for Comments

Industry Trades recommend adding GOR analyses as an allowable calculation methodology.

EPA is seeking comments on whether adding a laboratory measurement of the GOR from a pressurized liquid sample is an appropriate calculation methodology for atmospheric storage tanks. The Industry Trades are supportive of adding this GOR method to calculate emissions from storage tanks and emphasize that these samples do not need to be taken on a site-by-site basis to be representative.

3.7 Associated Gas Venting and Flaring

EPA is proposing to require reporting of associated gas venting and flaring on a site-by-site basis. The Industry Trades recommend that EPA keep emissions and associated data rolled up to the basin-level (or county-level, as required by other regulatory programs, such as PHMSA).

EPA is seeking comment on whether to continue to require reporting of GOR, produced oil volume, gas to sales volume, etc. The Industry Trades are in support of no longer requiring these reporting elements, unless required by the WEC. In general, the Industry Trades support efforts to streamline the data reporting process, particularly when the reported elements are not used to calculate emissions.

3.8 Flares

It is critical to the Industry Trades that the GHGRP does not directly include monitoring, measuring and sampling requirements for flares in order to avoid conflicting or duplicative requirements. Instead, the GHGRP should refer to data available through other applicable federal air quality regulatory programs. The Industry Trades request that EPA should ensure consistency across programs. This will help ensure that the requirements in the GHGRP are fully harmonized with any potential requirements under other federal air quality programs.

The Industry Trades support more accurate approaches for destruction efficiency for estimating flare emissions; however, the **tiers as proposed should be amended** (specific comments below). Further, while it is sensible to allow for the use of available empirical data and appropriate to define multiple estimation methods based on different types of available information, **monitoring requirements that are repeated in Subpart W rather than referencing the applicable regulation, especially those that exceed NSPS OOOOb and EG OOOOc requirements, which are defined in those rules, should not be included in Subpart W**. Further, flare estimating methods should be appropriate to the equipment and designs deployed within the segment (e.g., small, mostly unassisted, distributed flares) rather than arbitrarily under a rubric designed for a specific compliance assurance matter from a very different set of facilities and designs (refining and chemical manufacturing). Finally, flared emissions should be reported at the facility level rather than at the individual well pad or site, and especially not with attribution to the flare gas source.

With the Industry Trade's recommendations, the Industry Trades generally support EPA's focus on pilot flame monitoring as unlit flares can be large sources of methane emissions from flares. However, the proposed rule's requirements to continuously measure or monitor flow volumes, as well as use continuous gas analyzers or pull quarterly samples for gas compositions would result in little benefit to accuracy while posing significant costs and safety risks. Further, the Industry Trades disagree with EPA's proposed three-tier destruction efficiency (see Comment under Section 3.8.4 below).

3.8.1 Flow Measurement

3.8.1.1 EPA Should Continue to Allow Process Simulation and Engineering Calculations for Flare Flow Volumes

The Industry Trades recommend that EPA continues to allow the use of process simulation and engineering calculations that indirectly measure flare flow volumes as an alternative to meters or parametric monitoring devices. The proposed flare metering requirements are infeasible, burdensome and may lead to inaccuracies for most flares in production and gathering and boosting operations. Furthermore, EPA did not address the need to measure flare flow in the proposed rule's TSD. Likewise, the proposed parametric monitoring does not provide a more accurate or cost-effective alternative to metering. **EPA should retain the current Subpart W language stating that, "…If all of the flare gas is not measured by the existing flow measurement device, then the flow not measured can be estimated using engineering calculations based on best available data or company records. If you do not have a continuous flow measurement device on the flare, you can use engineering calculations based on process knowledge, company records, and best available data."**[26]

Proposed Flare Measurement Methods are Inaccurate and Infeasible for Low Pressure Flares

The proposed flare flow measurement methods are inaccurate, as well as infeasible, for low pressure flares in production and gathering and boosting operations.

The primary streams that are routed to flare at typical oil and gas facilities include:

[26] Current § 98.233(n)(1)

- Low-flow pilot, purge, sweep, and/or auxiliary gas used to ensure flares are lit, operating safely, and have optimal destruction efficiencies;
- Low- pressure gas that is intermittent and turbulent from tank flashing, working, and breathing losses;
- Mid- pressure flaring from low pressure/secondary separators, heater treaters, and vapor recovery towers that have become technically and economically compressed to sales that has intermittent and turbulent flow; and
- High pressure separator gas flaring in areas with stranded gas pipeline take-away loss that has intermittent flow and is decreasing across the country.

Most meters are unable to accurately measure the flow of low-volume, low-pressure, intermittent, and turbulent streams.

In addition to the concerns surrounding the metering of each individual stream, the Industry Trades are concerned with EPA's application of flow meters or parametric monitoring across every upstream application. EPA's requirement to use continuous flow measurement devices or parametric monitoring for low-pressure flares and purge/sweep/auxiliary gas streams is technically infeasible. Meters require steady pressure and flow to accurately measure flow rates. Most meters are unable to accurately measure low pressure and flow conditions found in purge/sweep/auxiliary gas and storage tank streams, or variable flows affecting several streams, such as tanks due to production slugs or when separators dump fluids, sporadic flaring of associated natural gas, and high-pressure equipment blowdowns. Furthermore, the flare volumes rapidly decline from the initial production of the well and become more sporadic. Metering the scenarios described is challenging, and industry needs a flexible array of options to ensure proper combustion and accurate reporting. The incorrect application of meters or parametric monitoring devices can lead to inaccurate flare volumes relative to using process simulations, engineering estimates, and indirect measurement allowed under the current rule. **The Industry Trades recommend the use of process simulation and engineering calculations that indirectly measure flare flow volumes as an alternative to meters or parametric monitoring devices.** The industry utilizes reliable process simulation and engineering calculations which are often more accurate than metering low pressure, low flow, and highly variable streams within the upstream oil and gas industry. The Agency and industry rely on process simulation and engineering calculations in permitting, designing and maintaining facilities for safety and environmental reasons, and have made great strides in the accuracy of these approaches in recent decades. Additionally, the GHGRP allows process simulation to estimate composition and volume of gas for emissions (e.g., tank flash gas, dehydrators, etc.) that are not going to flare so the same methods should be allowed for gas streams that do go to flare. As such, it does not make sense to expend significant capital and operational resources to install continuous monitoring when engineering estimates are more reliable and allowed for uncontrolled sources (e.g., storage tank vents and dehydrators). Interestingly, EPA couples burdensome, although potentially less accurate, measurement technology for flow with default destruction efficiencies, without allowance for measurement or performance test data; this would negate any possible improvements in flare emissions accuracy.

In Colorado, the Air Pollution Control Division (APCD) recognized that flow meters have low accuracy at low vapor volumes by first approving a variance in 2022 to their flow meter requirements and more recently amending their Regulation 7 rule language in 2023 to include pressure actuators as an alternative to flow meters. Pressure actuators are an example of a solution implemented to ensure combustion. For reporting purposes, engineering estimates and simulation software based on site specific information (e.g., GOR and liquid throughput) are more accurate to generate emissions reporting information for flares in the production and gathering and boosting operations. It is important that the EPA understands that proper combustion and accurate reporting go hand in hand and should be viewed holistically so that operators are efficiently managing both concerns.

Meters available in the market and widely used in upstream oil and gas applications include differential pressure meters (e.g., orifice plate and v-cones), thermal mass meters, and ultrasonic meters. Differential pressure meters work by measuring the upstream and downstream pressure from a plate or cone with an orifice that allows gas to pass through. The amount of differential pressure can be increased or decreased for any given flow rate by selecting plates or cones with smaller and larger orifices. The flow of the gas passing through the meter can be inferred by the differential pressure between both points. The ratio of minimum and maximum capacities of meters, known as the turndown ratio, typically should not exceed 4:1 for differential pressure. This causes three primary considerations for differential pressure meters: first, they are inaccurate in low-pressure conditions; second, they are unable to accurately measure variable flow rates given their relatively tight turndown ratio (Zhang & Wang, 2021);[27] and lastly, they are sensitive to liquid and debris clogging the orifice causing an artificial increase in differential pressure and inaccurate high flow volume measurements. The relationship between low-pressure conditions, tight turndowns, and sensitivity to operating conditions is exacerbated by the fact that smaller orifices must be selected for lower pressures, causing even tighter turndown ratios that are more inaccurate with variable rates, and increasing the likelihood of clogging. Orifices can also become blown out by sudden increases in flow volume or debris, which causes a decrease in differential pressure and inaccurate low flow volume measurements. This makes differential pressure meters technically infeasible to measure purge, sweep and auxiliary gas lines that operate at low pressures, tank vent lines that operate at near atmospheric conditions, and high-pressure gas lines that are more variable than the turndown ratio of these meters.

Thermal mass meters operate on the principle of thermal dispersion, which states that the amount of heat absorbed by a fluid is proportional to its mass flow. These meters work by either comparing heat loss between two elements, or by measuring the amount of energy that must be expended to heat gas to a certain setpoint. Similar to differential pressure meters, thermal mass meters cannot accurately detect lower flow rates due to the unmeasurably small differences in temperature between the two elements or energy required to heat gas for low flow volumes. As noted in Kerr-McGee's letter to Colorado Department of Public Health & Environment Air Pollution Control Division (APCD) dated April 12th, 2022[28], the turndown ratio of thermal mass meters is typically 33:1, which means the meter is unreliable until 3% of the meter's maximum flowrate of 1,180 thousand standard cubic feet per day (MCFD) is achieved. Additional information regarding this comment can be found in Annex C of this letter. This also makes thermal mass meters technically infeasible to measure pilot/purge gas lines and tank vent lines as these streams do not meet the minimum flowrates required for thermal mass meters due to their low rates and declining production over time. In addition to issues with low flow rates, thermal mass meters are highly susceptible to entrained mist, liquid, or particles that can affect the

[27] Zhang, Y and Wang, J. *Review of metering and gas measurements in high-volume shale gas wells*, Journal of Petroleum Exploration and Production Technology, 12:1561-1594, December 2021, https://doi.org/10.1007/s13202-021-01395-9.
[28] APCD-PHS-EX-035.

thermal properties of the gas being measured (API, 2021).[29] For example, the specific heat capacity of propane increases from 1.67 kJ/Kg-K in the gaseous phase to 2.4 kJ/Kg-K in the liquid phase. Thermal mass meters can measure dry gas in steady flow conditions above their minimum capacity, which makes them suitable for select flare scenarios depending on facility design and process. However, they do not have the level of accuracy required to form any basis for the methane fee.

Ultrasonic meters operate on the principle of doppler shift by measuring the time it takes for sound to travel from an ultrasonic signal transmitter to a receiver upstream and downstream of gas flow. Generally, ultrasonic meters do not work well in low flow conditions because of the unmeasurably small doppler shift that occurs at lower velocities. Thus, they are technically infeasible to accurately measure low pressure pilot/purge gas and storage tank streams. They are also sensitive to mist, liquids, or particulates that may block the receiver from receiving the ultrasonic signal, but not as much as differential pressure or thermal mass meters. They are also sensitive to surrounding equipment that may produce vibrations or sounds near the same frequency as the ultrasonic signal. For more information, refer to *API Manual of Petroleum Measurement Standards*, Chapter 14.10.[30]

It is important to note that meters can only be used when facilities have a dedicated high-pressure flare as opposed to a single control device (i.e., a flare that controls tanks, associated natural gas (ANG), and potentially other sources). Ultrasonic meters are also economically infeasible given they can cost $20,000 to $30,000 each to purchase, and additional capital required for installation and labor. API commented on this in our comments on NSPS OOOOb and EG OOOOc Supplemental Proposal, submitted on February 13, 2023, and included in Annex C of this letter. Furthermore, this does not include the cost to install SCADA communications systems that can cost up to $100,000 per facility for unconnected remote locations.

Proposed Parametric Monitoring Does Not Provide a More Accurate Alternative

The proposed alternative of parametric monitoring does not provide a more accurate or cost-effective alternative to metering.

Based on operator experience, field testing programs comparing parametric monitoring and metered flare volumes have shown that parametric monitoring over-estimates flow volumes. Implementing parametric monitoring to estimate flow is complex and requires detailed data on the appropriate flow orifice diameter, installing additional instrumentation to monitor temperature and pressure difference across the orifice, as well as the need to install SCADA communication systems at remote locations and analytical software to estimate flow rate. The requirement to either install meters or parametric monitoring systems is burdensome and unnecessary considering that the main contribution to GHG emissions from flaring is unlit flares, which are addressed separately in the proposed rule.

For all the reasons stated above, **the Industry Trades recommend that EPA continues to allow the use of process simulation and engineering calculations** that indirectly measure flare flow volumes as an alternative to meters or parametric monitoring devices.

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[29] American Petroleum Institute (API), *Manual of Petroleum Measurement Standards, Chapter 14.10, Natural Gas Fluids Measurement – Measurement of Flow to Flares*, Second Edition, December 2021.
[30] Ibid.

3.8.1.2 Proposed Flare Flow Measurement and Monitoring Requirements are Overly Burdensome

The cost and burden associated with measuring every stream is significant and understated by EPA.

Continuously measuring flow volumes or utilizing parametric monitoring devices for each source that routes gas to a flare will be extremely burdensome while failing to result in more accurate emissions reporting. Many operators have thousands of flares that would be affected, requiring either new meters or parametric monitoring devices. The majority of flares would require at least two gas streams to be monitored - the main vent line or "waste gas" stream and the purge/sweep/auxiliary gas stream. The cost and burden impact of monitoring – at a minimum – must include:

- Minimum of 2 or more specialized meters, or parametric monitoring systems
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofitting the flare line for the run for the meter
- Expanding or adding the remote facility computer (remote oil field controller)
- Expanding or adding data storage capacity on site
- Wiring to the remote facility computer
- Expending or adding the remote transmitting unit
- Calibration and maintenance
- SCADA and alarm programming
- Data management system
- Data review and analytics
- Data entry for calculations

The capital and operational costs to continuously monitor flare volumes using meters or parametric monitoring devices, as proposed, would result in significant costs to reporters that were not adequately addressed in the proposed rule's burden assessment. EPA did not explain the cost estimates in Table A-3 of "Assessment of Burden Impacts for Proposed Greenhouse Gas Reporting Rule: Revisions and Confidentiality Determinations for Petroleum and Natural Gas Systems," and we note that significant contributions to cost and burden were likely not included in the analysis based upon the magnitude of the estimate. As important, however, is the unjustified acceleration of installation of equipment that is already anticipated over the course of the next few years.

Paradoxically, this increased capital and operational cost can lead to flare volumes becoming less accurate than using the methodology under the current rule, as described below.

The requirement to continuously monitor at least two streams for thousands of flares at remote locations across the upstream oil and gas industry would require significant capital and operational expenditure with little benefit given the legitimate concerns regarding meter accuracy. As noted above, continuous monitoring flare flow volume would require costly specialized meters. As such, the Industry Trades believe EPA has underestimated the capital cost burden for purchase and installation of continuous parameter monitoring systems. The Industry Trades provided the Office of Management and Budget (OMB) this comment in response to Docket ID EPA-HQ-OAR-2023-0234.

3.8.1.3 Proposed Timeline for Flow Measurement or Monitoring is Unrealistic

If EPA does not continue to allow process simulation and engineering calculation for flare flow volumes, we are concerned about EPA's proposed requirements to expedite the installation of additional continuous monitoring systems on flares.

The deployment of new continuous metering or parametric monitoring equipment can pose significant challenges. This is particularly true for extensive oil and natural gas production sites and midstream assets, as they often lack SCADA systems or comparable infrastructure. This deficiency limits the connectivity of in-field instrumentation and access to a data historian. Additionally, the absence of necessary infrastructure, such as electricity and data infrastructure including Wi-Fi and even cellular coverage, further diminishes any cost-effective means for installing new instruments.

Existing supply chain delays would only be exacerbated by requiring flow meters on flares as proposed. Operators are currently facing ongoing COVID-induced supply chain delays of up to 12 months for flow meters; these timelines are expected to be lengthened to up to 24 months upon NSPS OOOOb finalization. These timelines account only for supply chain delays and do not contemplate the additional time needed to install equipment. These supply chain challenges for flow meters and other equipment were documented in a blinded operator survey submitted to EPA on September 20th (and included in Annex E of this letter).

As noted in API's previous comments on NSPS OOOOb and EG OOOOc:[31] "In addition to the supply chain delays in acquiring the monitoring equipment, installation of the monitoring equipment for existing control devices will require a hot tap on the control device piping or a site shutdown. A hot tap is a specialized procedure to make new piping connections, such as those required to install monitoring equipment, while the piping remains in service. Hot taps require high flow rates to facilitate heat transfer during welding, and so additional purge gas may be needed depending on the site gas production. This procedure presents a higher safety, fire, and explosion risk. Due to this elevated risk and specialized nature, operators are currently experiencing delays of approximately 4 months or more to schedule a vendor to perform a hot tap." Like the supply chain delays, finalization of NSPS OOOOb and the potential need for flow meters under Subpart W would only exacerbate current installation timelines. Instead of requiring all flare stack emissions to install flow measurement by January 1, 2025 (less than 18 months between the proposed rule and the applicability date and likely less than 12 months from final rule) the proposed revisions should allow operators to transition to measurement data as it becomes available through the implementation of NSPS OOOOb or EG OOOOc, which will incorporate practicable implementation schedules for monitoring requirements.

3.8.2 Pilot Flame Monitoring

The Industry Trades generally agree that it is more appropriate to identify discrete periods where flares are unlit for the purposes of estimating emissions that go un-combusted; however, several revisions should be made to the specific requirements:

1. **Double counting of emissions during periods of time when the flare is unlit should be avoided.** Because operators will identify discrete periods of time where the flare is operating with 0% combustion efficiency and report emissions accordingly, this volume of emissions should not be included in destruction/combustion efficiency (more in section 3.8.4 below).

[31] Comment 5.2. https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428

2. Monitoring for the presence of a pilot flame or combustion flame using a device capable of detecting that the pilot or combustion flare is present should **only be required for periods of time where there is flow of regulated material** going to the flare rather than "at all times."
   (i) It is illogical to track the length of time a flare is both unlit and there is zero flow because it has no impact on the estimated emissions.
   (ii) Additionally, automatic ignition systems have been deployed many operators and include a flame monitoring device. Since these devices include a flame monitoring device, they would satisfy the obligation, where EPA affirms the requirements for monitoring only apply during periods of flare flow. To reduce emissions or in areas where supplemental gas is needed because the well does not produce gas or enough gas, many operators are installing automatic ignition systems that activate when flow to the flare is detected instead of maintaining a continuous pilot flame. By design, an automatic ignition system will be unlit during periods with no detectable flow to the flare or the valve to the flare is closed. Some state rules, such as in New Mexico and Texas, allow for the use of an automatic ignition system with a flame monitoring device in lieu of a continuous pilot flame. The Industry Trades commented on the benefits of automatic ignition systems in Section 5.6.3 in our response to EPA's Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources" Oil and Natural Gas Sector Climate Review, Submitted February 13, 2023 (included in Annex C of this letter).
3. **Additional monitoring flexibility will improve accuracy of reporting and should be afforded to the pilot monitoring**. The Industry Trades recommend either removing the sentence in 40 CFR 98.233(n)(2), stating "if you continuously monitor, then periods when the flare are unlit must be determined based on those data" or revising it to allow redundant and/or additional parametric monitoring or visual inspection to be used. This is because monitoring device malfunctions are not uncommon for thermocouples (or equivalent devices) resulting in false readings; however, other monitored parameters can confirm that the pilot is, indeed, lit even if the monitoring device errantly indicates the pilot is unlit. For example, operators that have flares with multiple thermocouples to monitor flame temperature report that the readings can be widely variable and have observed that the presence of a flame can be indicated by a single thermocouple within the installed group. There are also cases where a pilot has malfunctioned, but visual inspection using site visits or cameras on location reveal a robustly lit combustion flame. In extreme weather conditions, such as in Alaska, Wyoming, or North Dakota, the thermocouple reading will be affected by the ambient temperature and wind conditions. So, where a monitoring device indicates the absence of a pilot flame or combustion flame, an operator should have the option to confirm that finding through other means and eliminate that period from the log of time in which the flare is unlit if supported by other data.
4. As an alternative to thermocouple monitoring, the Industry Trades recommend that visual inspections can be performed using cameras on location.

The Industry Trades commented on the benefits of automatic ignition systems in Section 5.6.3 in our response to EPA's Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources" Oil and Natural Gas Sector Climate Review, Submitted February 13, 2023 (included in Annex C of this letter).

3.8.3 Gas Composition Requirements

Similar to the discussion regarding requirements for flow monitoring in this letter, the Industry Trades **urge EPA to retain the option "to use the appropriate gas composition for each stream of hydrocarbons going to the flare" in the absence of a continuous composition analyzer.** The proposed requirements to either use a continuous composition analyzer or take quarterly samples are both unnecessary (source flow composition is relatively stable at oil and gas facilities) and potentially conflict with the specific requirements and implementation timing of compliance assurance requirements in NSPS OOOOb and EG OOOOc.

EPA should provide an option to use process models for flared gas, which is how most compositions are currently being determined and with reasonable accuracy.

The proposed requirements to measure or sample the gas composition for each flare are economically and technically infeasible, and engineering estimates and representative analysis should be allowed.

EPA's requirement that quarterly gas samples be pulled for each stream that goes to flare has no basis and was not addressed in the proposed rule's TSD. The proposed requirement to install a continuous gas analyzer or take quarterly samples of the inlet gas to every flare is unreasonable and burdensome for several reasons.

1. **The gas composition is relatively stable over time rendering more frequent characterization of low value**. Flare gas composition in oil and gas operations is relatively stable and will not change significantly over time. As discussed above, the primary streams going to flare at typical oil and gas facilities include:
    - Pilot, purge, sweep, and/or auxiliary gas;
    - Low-pressure gas from tank flash, working, and breathing losses;
    - Mid-pressure flaring from low pressure/secondary separators, heater treaters, and vapor recovery towers that have become technically and economically compressed to sales; and
    - High-pressure separator flaring in areas with stranded gas pipeline take-away loss which is intermittent and decreasing across the country.[32,33]

    EPA also recognized that the gas composition could be stable by proposing an alternate net heating value demonstration in NSPS OOOOb and EG OOOOc[34]. While Industry Trades commented that this demonstration should be simplified due to the relatively stable and generally sufficient heating value of the gas streams, its inclusion in the compliance assurance requirements of NSPS OOOOb and EG OOOOc recognizes that the gas streams could be demonstrated to be stable.

2. **EPA has not justified the costs related to the installation of continuous composition analyzers or quarterly sampling, and go beyond NSPS OOOOb and EGOOOOc compliance assurance requirements**. Installation of a continuous monitor for each stream or quarterly sampling will be

[32] https://www.api.org/news-policy-and-issues/blog/2022/05/24/reports-us-among-world-leaders-in-reducing-flaring.

[33] https://www.hartenergy.com/exclusives/us-reduces-flaring-and-flaring-intensity-world-bank-says-204724.

[34] Proposed § 60.5417b(d)(1)(viii)(C)(1) to (5).

extremely costly for installation, data gathering and management, calibration and maintenance or sampling and analysis for the thousands of flares impacted. Costs for continuous monitors include:

- Monitor(s) (one for each stream)
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofitting the flare line for the continuous analyzer
- Expanding or adding the remote facility computer (remote oil field controller)
- Expanding or adding data storage capacity on site
- Wiring to the remote facility computer
- Expending or adding the remote transmitting unit
- Calibration and maintenance of the monitor
- SCADA and alarm programming
- Data management system
- Data review and analytics
- Data entry for calculations

For quarterly sampling, the associated costs include:

- Minimum of 2 sample ports (one for each stream)
- Labor for installation
- Loss of production for shutdowns for installation
- Retrofitting of the flare line for the sample ports
- Cost of gathering the samples each quarter
- Cost of analyzing the samples every quarter
- Data management system
- Data review and analytics
- Data entry for calculations

Flare systems in upstream operations are not designed for sampling, meaning that physical modifications to install sampling ports would be required to enable samples to be taken, which is costly and not always technically feasible. Also, installing sampling ports, meters/instrumentation, or continuous gas analyzers would require production to be shut down, which would be logistically challenging and generally result in flaring to accommodate causing more emissions.

As noted in API's comments on NSPS OOOOb:[35] "Calorimeters and other compositional analyzers (e.g., gas chromatographs or mass spectrometers) have an approximate minimum installed cost of $164,000 to $245,000." The estimated cost per gas sample was "$1,500 to $2,000 including shipping and analysis." Therefore, the annual cost for quarterly sampling could easily exceed $10 million for an operator considering 4 samples per year per stream, at least 2 streams per site, and a thousand or more sites to sample annually.

[35] Comment 5.6.4. https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428.

Finally, a continuous compositional monitor or quarterly sampling goes beyond the continuous net heating value (NHV) monitoring or NHV demonstration required under proposed NSPS OOOOb and EG OOOOc. As stated at the beginning of this section, Subpart W must not impose monitoring requirements beyond other applicable regulations. While a continuous compositional monitor could be used for NHV monitoring, compositional analyzers (e.g., gas chromatographs) are more expensive than NHV monitoring devices (e.g., calorimeters). Given the relatively stable composition of gas streams and cost for compositional monitoring, Subpart W should simply reference NSPS OOOOb and EG OOOOc monitoring requirement as they relate to methane destruction efficiency (see comments bellow) and not impose additional composition monitoring requirements.

3.8.3.1 Supply Chain Constraints

As noted above for flow meters, operators are currently facing ongoing COVID-induced supply chain delays of up to 12 months for monitoring equipment for flares; these delays are expected to be lengthened to up to 24 months upon NSPS OOOOb finalization. Requiring compositional monitoring under Subpart W would further exacerbate the existing supply chain constraints with minimal benefit to reported GHG emissions.

3.8.3.2 Technical Feasibility Issues

Additionally, it is technically infeasible to pull gas samples from low pressure flares. A positive pressure is required to pull gas samples from flare lines. Low pressure flare vent lines operate at near atmospheric conditions, which would either take hours to collect a large enough sample (i.e., fill a bag with enough gas) to send to laboratory for analysis or require a gas chromatograph equipped with a pump to be brought on location. Requiring a gas chromatograph to pull quarterly gas samples is economically infeasible.. Process simulation would be a more accurate representation of tank gas. It would be equally difficult to pull samples for mid- and high-pressure flaring given the intermittent nature of these events. A more accurate representation of high-pressure gas composition, as well as pilot/purge gas, would be sales gas composition which is ultimately what is being combusted at the flare. Finally, as stated above, EPA does not address why this frequency in sampling is being proposed in either the Technical Support Document or the preamble.

3.8.4 Variable 'Combustion Efficiency' Based on Compliance and/or Monitoring

Tier 1 methods should allow an option to perform combustion efficiency testing or performance test data to validate a combustion efficiency assumption of 98% or greater. Tier 2 methods should provide a default combustion efficiency of 98%. The default factor in Tier 3 should be revised to a minimum of 95%.

3.8.4.1 NESHAP CC Requirements Are Not Applicable to Subpart W Flares

The reference to and requirements from refinery NESHAP CC are not applicable for Tier 1 reporting under Subpart W.

EPA should remove any tier requirement related to NESHAP CC for refineries because the characteristics of the flare designs, operating conditions, and composition variability are not representative of, and in fact quite dissimilar from, petroleum and natural gas systems flares.

The Industry Trades believe the reference to NESHAP CC which applies to petroleum refineries is inappropriate. There are numerous ways in which refinery and chemical manufacturing flares and flare gas differ from that of upstream and midstream.

- Flare gas composition and flows span large ranges: Refinery flares receive flare gas of highly variable composition and of varying levels of heat content. Refinery flares can be dedicated to one or more related process units but are quite often very large and in service to many different process units, or even operate as a single interconnected system. Resultantly, the range of flows and composition to the flare is highly variable over a matter of hours. The heating value of the streams is typically much higher in upstream and midstream with the high-pressure gas being primarily natural gas and the gas from secondary separators, heater treaters and vapor recovery towers having a higher heating value greater than 2000 btu/scf. Except for the minority of wells that produce inert gases, where the composition of that production is known, flare gas streams are always highly combustible.
- Because refinery and petrochemical manufacturing flares combust gases with greater propensity to produce smoke (e.g., concentrations of olefins, diolefins, and aromatics) and thus are generally designed with an emphasis on smoke control, often including one or more steam addition systems, there is a documented risk of “over-steaming” for these flares. Less frequently, refinery and chemical manufacturing flares are air assisted, and even more rarely, unassisted. The reverse trend is true for upstream and midstream flares, where steam assist is the exception to the norm. Utilities to support steam assist are generally not available, upstream flares are less likely to need commensurate smoke suppression systems, and upstream and midstream flares are much smaller and dedicated units.
- While upstream operations are also actively seeking to reduce flaring, Refinery and chemical manufacturing flares also often have an obligation to flare gas minimization. Accordingly, any routine flaring that exceeds the flare gas recovery capacity of the facility results in flaring at extremely high turn-down conditions for the flare. High turn-down (<0.1% of flare capacity) at a steam-assisted flares presented the perfect storm for degraded combustion efficiency, which drove the enforcement initiative, subsequent ICR testing, and ultimately rulemaking to address this specific conditions. This condition does not exist in the up- and midstream segments.

3.8.4.2 EPA Should Allow Direct Measurement and Performance Testing for Flare Methane Destruction Efficiency

Direct measurement and performance testing by manufacturers or operators should be accepted as an optional demonstration of even greater destruction efficiency beyond 98%.

The Industry Trades request that EPA allow directly measured data, as well as NSPS performance testing by manufacturers or operators, as a more accurate approach to quantify an individual flare’s methane destruction efficiency. Whether or not a flare is monitored pursuant to NESHAP CC or NSPS OOOOb has no actual bearing on the flare combustion efficiency values. Even if a flare meets the monitoring requirements of either rule, it does not necessarily follow that the actual flare combustion efficiency is at the respective values. For example, flow volume values may indicate flow exceeding minimum or maximum flows which is an indicator of potential suboptimal combustion efficiency. Additionally, if all monitored flare values are within performance standards, the flare combustion efficiency could be higher than the specified combustion efficiency for the specified tier. As is standard practice with GHG estimation methodologies, the timing and values of detections, measurements, and parametric data—not whether monitoring requirements are met--determine emission rates, such as flare combustion efficiency. Thus, the Industry Trades recommend that EPA supplement the tiered monitoring approach to flare combustion efficiency reporting to include directly measured data or NSPS performance testing by manufacturers or operators.

Some operators are deploying emergent technologies to directly measure combustion efficiency (or the closely related destruction efficiency) for flares, such as Providence Photonics Mantis and Mantis light (additional information regarding this technology is available in Annex D). Many operators, either through state or permit requirements, or voluntarily, conduct more traditional stack testing to assure high combustion efficiency of enclosed combustors, which also meet the definition of "flare" in Subpart W. Both of those testing methodologies provide the most accurate estimate of any particular flare and should be allowed as an option.

EPA should also allow for the use of the recently finalized "Other Test Method (OTM 52): *Method for Determination of Combustion Efficiency from Enclosed Combustion Devices Located at Oil and Gas Facilities*,"[36] using Portable Analyzers to determine destruction or combustion efficiency.

These approaches would further support technology development and allow for flexibility in using advanced and evolving technologies. For example, the Department of Energy is currently in year two of funding for the ARPA-E REMEDY program (REMEDY | arpa-e.energy.gov) that has a stated goal of developing technical solutions to achieve 99.5% methane conversion in flares. If technology development from this 3-year, $35 million research program is successful, the ability to use a higher flaring efficiency value in methane emissions reporting could help to drive greater adoption of new technologies in operations.

3.8.4.3 Requirements for Proposed Tier 2 Support 98% Methane Destruction Efficiency

The compliance assurance provisions in NSPS OOOOb and EG OOOOc, as proposed under Tier 2, are sufficient to ensure 98% methane destruction efficiency.

The underlying goals of the flare compliance assurance provisions in part 63 subpart CC flare requirements was to supplement the provisions in 60.18 to specifically protect against over steaming, especially in concert with lower heat content flare gas by transitioning the compliance point from heat content of flare gas to heat content reaching the combustion zone, which would account for inert gases introduced to the flare gas within the variable gas composition in manufacturing settings, and account for the impact of steam on the combustion zone. In the absence of those conditions, 60.18 provisions continue to provide a reasonable assurance of high combustion efficiency.

Further, a recent study on flare destruction and removal efficiency (DRE) conducted in the Permian Basin by members of the Industry Trades indicates that over 85% of flares have a destruction efficiency above 98% (refer to comment below in Section 3.8.4.4). Other available member-provided destruction efficiency test data from the Bakken, which includes 92 individual flare measurements, show that over 90% of the flares tested had a destruction efficiency of 98% or higher, and over 75% were higher than 99% destruction efficiency. These findings support a 98% combustion efficiency default for Tier 2, especially considering the enhanced monitoring requirements aligned with NSPS OOOOb rule requirements.

[36] https://www.epa.gov/system/files/documents/2023-09/otm-52_method-for-determination-of-combustion-efficiency-from-enclosed-combustors_clean_8_31_2023-004.pdf.

3.8.4.4 Tier 3 Methane Destruction Efficiency Should be Revised to a Minimum of 95%

Destruction Efficiency of 95% Supported by Plant *et al* Study

The default proposed 'combustion efficiency' in Tier 3 reporting is based upon errant analysis in the Plant *et al* study and a more appropriate interpretation of those data would result in an overall methane destruction efficiency of >95% across upstream and gathering and boosting flares.

The Plant *et al* published study results state that 'the majority of flares function close to expected performance, with DRE values near 98%.'[37] The study concluded that approximately **95% methane destruction efficiency was the average across the basins in the study without accounting for unlit flares**. Since Subpart W already requires the monitoring of and segregation of periods where flares are unlit, it is not appropriate to *also* include that condition in an average destruction efficiency assumption. The average observed DRE across the three regions of study is 95.2% and the average total effective DRE after accounting for unlit flares is 91.1%.[38] The lower 'combustion efficiency' proposed by EPA is not aligned with the methane destruction efficiency findings from the Plant *et al* study, and represents the inclusion of unlit flares, **meaning that the unlit flare contribution would effectively be double counted since unlit flares are reported separately.** Therefore, 95% methane destruction efficiency would be more appropriate for Tier 3 as supported by the study referenced by EPA (rather than 92%). This 95% destruction efficiency would be aligned with NSPS OOOO and OOOOa control requirements; requiring a Tier 3 efficiency of 92% would not be aligned with other applicable requirements.

Furthermore, in the Plant *et al* study, investigators did not have access to operational data, including flow information, for any of the observed flares. Resultantly, extrapolation of the observations to a regional emission factor inherently assumes that the set of flares observed well represented the population of flares in terms of size, design, and most importantly, flow rates. In the case of refinery and petrochemical plant flare combustion efficiency studies, it was found that flares most at risk for reduced combustion efficiency were those operating at high turndown (low flow) conditions. Low flows also result in reduced exit velocity, where higher exit velocities are more protective against cross-winds. Therefore, it is quite plausible that the majority of the flares encountered in the Plant *et al* study that were operating at reduced combustion efficiencies were flares at low flows. However, the authors applied the destruction efficiencies by *count* of flares to regional flare gas estimates from the Visible Infrared Imaging Radiometer Suite (VIIRS), which inherently incorporates an assumption that flare gas was evenly distributed among the observed flares and that flare turndown was not correlated to combustion efficiency degradation.

Validity of the Plant *et al* Study Data is Questionable

The validity of the Plant *et al* study data as the sole underlying basis for quantifying flare methane destruction efficiency is questionable.

There are several limitations of the Plant *et al* study, most of which are raised by the authors themselves within the study and quoted below. These limitations raise questions about the study validity as a basis for establishing a 3-tier combustion efficiency framework and a presumptive Tier 3 value of 92%. These include:

[37] https://graham.umich.edu/media/files/F3UEL-Fugitive-Emissions-from-Flaring.pdf.
[38] Ibid.

- The study design did not disclose how the flight-path test method (i.e., 'shifting racetrack' pattern) was validated, for example, using a well-characterized source of CO2 and CH4 or a test flare having known input flow rates, combustion characteristics, and dispersion behavior. Without documentation of method validation using a model source, peer reviewers were, and end-users are, unable to determine how the field sampling techniques were calibrated, and the appropriateness of the error correction / statistical treatment applied to the collected information to address test method-induced artifacts.

- There were no data presented on the vertical or horizontal dispersion effects or on the ability of the sampling technique to discern the presence of imperfect distribution of CH4, CO2 or other components within the sampled plumes. In fact, in the Supplementary Materials[39] the authors noted that (emphasis added), "In real-time, the concentration reading of CO2 was monitored to look for an intercept (i.e., peak) of the ***relatively narrow flare combustion plume as the aircraft transected downwind. If an intercept was not identified on the first downwind pass, the flight team adjusted altitude, using the visual flare as a guide***." This statement confirms that each sample event would likely have employed a unique flight path, introducing an inconsistency across individual runs in the dataset.

- The sampling scenario was challenging. As noted in the Supplementary Materials[40], "In real-time, the concentration reading of CO2 was monitored to look for an intercept (i.e., peak) of the relatively narrow flare combustion plume as the aircraft transected downwind." No information was available to readers to determine the parameters of each flight path. Using publicly available information for the aircraft and assuming a circular flight path, the estimated dwell time of the aircraft in the plume during each pass was likely extremely short. The Scientific Aviation Mooney aircraft have a cruise speed of 170 knots (or higher)[41] with stall speeds of 50-60 knots[42,43] according to various sources. At a speed of 130 knots[44] in a 6500ft diameter circular flight pattern, and assuming a 10^{o} sample window (570ft), the dwell time in the sample window is less than 2.5 seconds. Even with a wide 22.5^{o} sample window (1275 ft), the dwell time in the sample window is just 5.5 seconds. Higher air speeds would shorten the dwell times.

- The study acknowledged that the log-normal curve-fitting technique used likely leads to overweighting the importance of the outlying data, thus magnifying the influence of tails even though the authors noted that the median observed DRE values were close to 98%. Also, the authors could not explain the outlying, tail-defining observations collected (emphasis added), "Investigations into possible drivers of reduced DRE… did not yield compelling explanatory relationships, suggesting that the combination of our airborne sampling and these supplemental datasets ***cannot explain most of the observed flare CH4 DRE variability***." Also, the authors did not solicit input from operators about operating conditions that could explain the observed data. Given the influence of the low DRE datapoints, further scrutiny as to their validity and possible exclusion from the dataset should have been made.

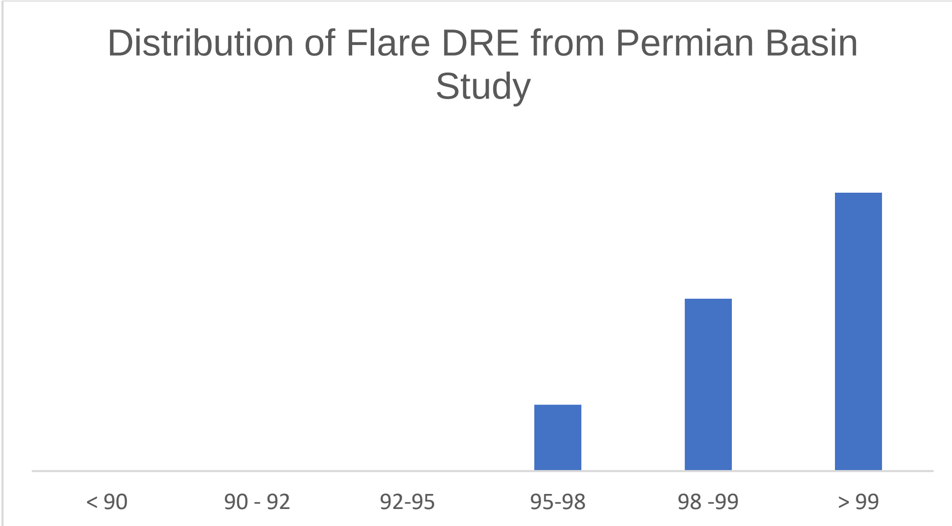
- The Plant *et al* study did not provide information on the rate, duration and variability of the gas being flared at each location, nor what activity precipitated the flaring, such as: flowback from a single well, emergency operations during drilling or a workover, a lightning strike that shut down control systems, a gas compressor failure, malfunction of a tank or separator liquid level or other controller, on a well pad co-located with the flare or at a central gathering and boosting facility, upset at a gas treating unit co-located with the flare, shut-in of a downstream gas plant forcing gas to be flared from multiple upstream sources etc. Absent this information, it is impossible to determine what separated high-performing flares, from those that exhibited low DREs and whether the low-performing flares represent the effect of transient anomalies that cannot be assumed to be present basin-wide for extended periods of time.

- The use of "bootstrapping sampling" to extend to basin-scale the data from the limited sample set collected via aircraft sampling magnifies the weaknesses discussed above and should not be the basis for a regulatory change. The Plant *et al* study authors combined contributions of both observed" inefficient **performance (*i.e., CH4 DRE*) and the prevalence of unlit flares into a total effective DRE."** This was done by randomly resampling (with replacement) the observed DRE distributions and applying those efficiencies to the population of flares seen in VIIRS within each basin. Essentially, this manipulation of the data multiplied the small observed dataset many times over. Then the authors ***inferred the uncertainty*** (emphasis added) of basin-average estimates to derive 95% confidence intervals. This approach does not support the use of the word "found" in the following statement made in the preamble: "Plant *et al*. … ***found*** average combustion efficiencies ranging from less than 92 percent in the Bakken basin to slightly more than 97 percent in the Permian basin."

Member-Provided Data Supports a Destruction Efficiency Well Over 95%

Additional flare destruction efficiency data provided by Industry Trade members indicate that all but two flares out of 132 tested achieve a destruction efficiency of over 95%, with the majority (nearly 90%) achieving a destruction efficiency greater than 98%.

In September 2023, API members conducted a flare study on 39 flares throughout the Permian Basin using Providence Photonics Mantis. Due to the limited timeframe in which to prepare comments, this study was limited to 39 flares; however, the study found that 85% of flares achieved a destruction efficiency greater than 98%. All flares achieved a destruction efficiency greater than 95%, as shown in the Figure below.



Other available member-provided destruction efficiency test data from the Bakken, which includes 92 individual flare measurements, and one measurement in the Permian, show that over 90% of the flares tested had a destruction efficiency of 98% or higher, and over 75% were higher than 99% destruction efficiency. All but two flares out of 92 tested had a destruction efficiency above 95% (i.e., 94.85% and 90.52 %, respectively). The table below summarizes the distribution of methane destruction efficiencies calculated from member-provided flare testing in both the Permian and Bakken basins:

Basin	Number of Flares Tested		Mean Flare Destruction Efficiency, %	Median Flare Destruction Efficiency, %
Permian	40		98.82	99.05
Bakken	92		99.27	99.69
Combined	132		99.14	99.50

As shown, the median flare destruction efficiency for the combined dataset of 132 flares tested from the Permian and Bakken was 99.5%. **These studies further reinforce that the Tier 3 destruction efficiency should be a minimum of 95%. Arguably, the Tier 3 destruction efficiency should be considerably higher than 95% based on the test data from members, as the data supports a destruction efficiency closer to 98%.** Please see Annex D for a summary of the test results.

3.8.5 Completion Combustion Devices Should not be Subject to Proposed 98.233(n)

Requirements for completion combustion devices used during completions with hydraulic fracturing should not be required to have the same monitoring provisions as flares under 98.233(n).

For completions with hydraulic fracturing in 98.233(g), EPA has proposed operators to follow the requirements listed in 98.233(n), which include extensive monitoring requirements. Under existing air quality regulations and proposed NSPS OOOOb, combustion of emissions that cannot be routed to sales, such as for wildcat or delineation wells, are combusted using a completion combustion device. This equipment has a separate definition and compliance assurance requirements from typical control devices based under NSPS due to the temporary use of these devices during a completion event. The proposed requirements under 98.233(n) are inappropriate and EPA should, at a minimum, have appropriate provisions that allow engineering estimates for completion combustion events. Completion combustion devices must be equipped with a reliable continuous pilot flame under NSPS.

3.8.6 Disaggregation of Flare Emissions

When data is not available to allow disaggregated reporting by individual sources controlled by a flare, EPA should allow aggregated emissions reporting by flare.

The Industry Trades understand that EPA wishes to allocate all individual sources controlled by a flare back to the contributing source. The Industry Trades support maintaining the ability to report emissions aggregated by flare when more accurate data is not available. As addressed in the "Flares" section of this document, metering individual sources may not result in more accurate data. Allowing the flexibility to continue reporting flare sources aggregated will give companies the ability to report the most accurate data available given a particular facility's operational design. However, it is important to note that EPA has not stated a clear benefit from requiring the disaggregation of sources, and therefore a true cost/benefit analysis cannot be determined.

3.9 Centrifugal and Reciprocating Compressor Venting

3.9.1 Measurements in Not-Operating-Depressurized Mode

The Industry Trades support EPA's efforts to increase the accuracy of reported information for venting from centrifugal and reciprocating compressors by allowing direct measurement, but measurement should not be required in Subpart W if not required in other regulatory programs. Additionally, Subpart W should not force operators to measure emissions in a not-operating depressurized mode.
EPA's proposed expansion from an emission factor to measurement approach for onshore production and gathering and boosting will further improve the quality of reported emissions across the segments. The Industry Trades support the expanded assortment of measurement methodologies and appreciate EPA's use of data from other programs (e.g., proposed NSPS OOOOb and EG OOOOc) for emissions calculations under subpart W, however there are numerous issues with the proposal. Although the compressor measurement provisions have been expanded from the gas processing reporting source category to include onshore production and gathering and boosting, there are unique differences that should be accounted for within the proposed requirements. The Industry Trades have provided suggested edits to account for these differences.

EPA is proposing to require that onshore production and gathering and boosting operators shall measure at least one-third of their reciprocating and centrifugal compressors subject to NSPS OOOOb in not-operating-depressurized mode each year. The Industry Trades do not support this requirement for several technical, safety and practical reasons. The Industry Trades recommend that EPA align with proposed NSPS OOOOb and EG OOOOc and limit the measurements to the rod packing for reciprocating compressors and dry seal vents for centrifugal compressors. Testing the compressors in a not-operating depressurized mode is unnecessary and very difficult to implement for the following reasons:

- Forcing a unit into a not-operating depressurized mode will result in unnecessary venting of methane emissions to the atmosphere and could pose an unnecessary safety risk to the testing personnel or others at the site. Operations in upstream production and gathering and boosting segments are characterized by stable operation with full utilization of installed compression capacity. In order to measure emissions in not-operating depressurized mode, a forced blowdown event leading to significant methane emissions would be required for these compressors.

- As a practical matter, it would be very difficult if not virtually impossible for an operator to know at which point during the year to force units into a not-operating-depressurized mode in order to reach a prescriptive annual target. Additionally, the number of units change on a frequent basis due to acquisitions/divestitures, such that the number that would constitute "one-third" changes from month to month. Compressors are also added and removed throughout the year to address operation needs from the wells and gathering system based on production rates.

- In the dynamic operations of upstream and midstream oil and gas, shutting down a compressor for the sole purpose of measuring the venting could result in shut-in and blowdown of other process equipment resulting in additional methane emissions, as well as costly prolonged downtime of a facility. Taking a compressor off-line in production and gathering and boosting segments would result in shutting in a well(s), which can be problematic to restart and regain stable operation. As anecdotal evidence, our members have noted these tests take upwards of three weeks at their 10 gas plants with 140+ compressors. Extending this requirement to upstream facilities that are geographically spread across hundreds of miles would be extensive due to the thousands of compressors in use. The gas plant measurements are streamlined due to the units being co-located and the designed redundancy in place.

- Additionally, due to the integrated nature of the upstream/midstream environment, shutting down compression would not only have an effect on that company, but would additionally impact other companies that are connected to the system (i.e., shutting a compressor down would cause high pressure issues for the upstream operator and low-pressure issues for the downstream operator potentially resulting in additional flare and/or vented emissions for additional companies.

- Methane emissions from compressors in not-operating depressurized mode represent the emissions across the isolation valve, with potentially high flow rates due to the extreme line pressure on the upstream, pressurized side of the valve. Many operators, especially in production and gathering and boosting segments, do not normally operate compressors in this mode due to the potentially large methane leakage and associated safety risks. Additionally, good operating practice is to leave the blowdown/depressurization valve closed when units are offline.

- Finally, many compressors serve a critical function in the electricity generation supply chain and operate with limited or no excess capacity; forcing operators to shut down units to take measurements in a not-operating depressurized mode could strain the electrical generation supply chain. In 2022, the Texas Railroad Commission (TRRC) adopted weatherization rules for natural gas facilities to protect gas flow to power generators and ensure that residents have electricity during weather emergencies. The new rule requires critical gas facilities to weatherize, to ensure sustained operation during a weather emergency. The testing requirements as described would add an additional layer of complexity with little to no emissions reporting accuracy improvements.

3.9.2 Alignment with NSPS Protocols – Measurement of Compressor Sources

In the proposal for NSPS OOOOb, rod packing, and seal vents are the only compressor sources that require monitoring. All other compressor leaks would be captured during the fugitive emissions inspections. The Industry Trades recommend that EPA align with the monitoring and fugitive emissions requirements of NSPS and consider leaks from other sources (e.g., blowdown valve leakage) fugitive leaks. This modification would eliminate the need for specific compressor mode testing and align with other EPA regulations for other sources.

3.9.3 Emission Factor Methodology- Utilize Measurement Data Reported Under Subpart W for Onshore Production and Gathering and Boosting

EPA should utilize the vast dataset of historically reported compressor measurements in different operating modes to derive population emission factors to ease the burden of compressor measurements and reclassify leakage from isolation and blowdown valves (open-ended lines) as equipment leaks.

While we believe all leaks besides rod packing and seal vents should be captured under the fugitive emissions reporting, EPA could consider an alternative to the measurement protocol. This alternative could utilize the vast dataset of compressor measurements in different operating modes historically reported under Subpart W to derive emission factors to reduce the burden of compressor measurement requirements. Because of the large sample size of actual measurement data, methane emissions can be reasonably estimated using emission factors derived from the data reported Subpart W.

Additionally, EPA should consider the use of the historically reported Subpart W compressor leakage dataset to derive population emission factors rather than rely on the much smaller dataset from the Zimmerle *et al* study.

3.9.4 Alignment with NSPS measurement provisions should extend beyond onshore production and gathering and boosting industry segments.

Industry Trades support referring to the data made available through the provisions located at §60.5380b(a)(5) for centrifugal compressors and §60.5385b(b) and (c) for reciprocating compressors at onshore production and onshore natural gas gathering facilities, but do not support incorporating measurement requirements in Subpart W. The Industry Trades recommend that EPA should also do the same for any compressor subject the NSPS OOOOb or EG OOOOc, including those located at onshore gas processing, natural gas transmission and underground storage. Without this alignment for all compressors subject to the NSPS, many operators will be required to calibrate measurements according to two separate standards, which we do not believe was EPA's intent.

3.10 Equipment Leaks

3.10.1 Method 2- Site-Specific Leaker Emission Factors

EPA should allow more flexibility in the requirements for developing site-specific emission factors for equipment leaks.

The Industry Trades support EPA's proposal to allow for directly measured data to develop site-specific emission factors in lieu of the default leaker or population emission factors for equipment leaks. However, the Industry Trades recommend allowing more flexibility in allowing representative direct measurements rather than "site specific." For upstream operations, there can be many components that are representative even if they are not located at the same facility; and the same can be said for the gathering and boosting reporting segment. The Industry Trades recommend that EPA allow representative leak measurements where "representative" could mean components in gas or oil service, component types, and other considerations – but not otherwise limited to a single well pad or boosting and gathering ID.

The number of leak measurements required to develop site specific emissions factors, proposed as a minimum of 50 per component type, is arbitrary; accumulating 50 leak measurements will be difficult for less frequently used component types or operators with fewer sites. The Industry Trades recommend that EPA allow operators flexibility to determine an appropriate sample size using an appropriate statistical approach based on the complexity of the sites (based on variability of the streams at the sites) and available data and modify as more measurements are obtained. The requirement for a sample of 50 leak measurements per component type will penalize small operators with few sites, as the minimum requirement of 50 may not be possible. Further, as operators convert pneumatic systems to air or electric controllers, fewer sites will have natural gas-operated pneumatics. The Industry Trades also recommend allowing multiple years upon which operators can collect measured leak data and refine those factors as more data is available; this will ultimately be more accurate and representative of site conditions than default emission factors that were derived from larger data sets.

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3.10.2 Method 1- Default Leaker Emission Factors

The derivation of the proposed OGI leaker emission factors is unclear and values appear high relative to the underlying studies and would overstate emissions from the more prevalent non-compressor related components.

The Industry Trades support the use of data from the Pacsi *et al* study to develop the leaker emission factors. However, we are concerned about the significantly higher emission factors that EPA has derived from the Pacsi *et al* and Zimmerle *et al* studies, especially for OGI leak detection, as compared to the existing Subpart W and Pacsi *et al* leaker emission factors. When comparing the published study results from Pacsi and Zimmerle to the EPA proposed emission factors (see comparison table below), it is unclear how the proposed emission factors were derived and while a generalized description is provided in the TSD, the supporting calculations are necessary to fully understand the approach EPA has taken.

Component	**EPA Proposed Emission Factors (scf/hr/component)**			**Pacsi et al (scf/hr/component)**	**Zimmerle et al, (scf/hr/component)[a]**	
	OGI	**Method 21 @ 10,000 ppm**	**Method 21 @ 500 ppm**		Non-compressor components	Compressor components
Leaker EFs, Gas Service – Onshore Production & Gathering and Boosting						
Valves	16	9.6	5.5	6.0	7.1	36.9
Flanges	11	6.9	4.0	13.7	6.2	8.8
Connectors	7.9	4.9	2.8	2.8	4.7	11.9
OELs	10	6.3	3.6	8.5	3.94	
PRVs	13	7.8	4.5	1.1	10.0	18.5
Pump Seals	23	14	8.3	-	29.9	
Other	15	9.1	5.3	4.2	21.7	
Leaker EFs, Oil Service – Onshore Production & Gathering and Boosting						
Valves	9.2	5.6	3.3	4.9	7.1	36.9
Flanges	4.4	2.7	1.6	-	6.2	8.8
Connectors	9.1	5.6	3.2	1.1	4.7	11.9
OELs	2.6	1.6	0.93	-	3.94	
Pump Seals	6.0	3.7	2.2	0.23	29.9	
Other	2.9	2.2	1.0	12.7	21.7	

[a]Zimmerle *et al* study published results did not distinguish between gas and oil service.

As shown in the table above, the Zimmerle *et al* study data show and the study report indicates that emissions from compressor-related components have higher leak rates due to vibration. Since EPA did not distinguish between components associated with or not associated with compressors, the average emission factors proposed that appear to include compressor-related components would overstate emissions from the more prevalent non-compressor related components. The Industry Trades request that EPA critically review the derived emission factors and include compressor-related components in the breakdown of leaker emission factors, with commensurately lower emission factors for non-compressor-related components, to avoid significant overstatement of methane emissions from the higher population of non-compressor related components.

Applying gathering and boosting derived emission factors to onshore production with compressor-related component emissions included in the Subpart W emission factors would significantly overstate methane emission because far fewer compressors are operational in production compared to gathering and boosting operations.

The Industry Trades support efforts to properly characterize a leak by the period in which that leak is detected. This will further align subpart W with the proposed methane rule, which mandates that any leaks must be repaired as soon as practicable. To that extent, we recommend EPA amend the definition of $T_{p,z}$ in Equation W-30 to better reflect the implementation of monitoring and repair programs by acknowledging that the duration of the leak may be subject to the action of repair and verification, and not solely by a traditional survey and/or the start or end of the reporting year, similar to what the Industry Trades propose for other leak durations, thief hatch openings, etc.

We also recommend that EPA revise the approach to include other activities in addition to leak detection surveys that may offer an indication of a repaired leak. While the current proposed language refers only to a “survey”, an operator will have other clear indicators that a leak has been addressed including the repair date or other detection approach. EPA should include any other such activity on which an operator seeks to assign a repair date other than a survey as a reporting element.

3.10.3 Enhancement Factor

EPA’s ‘Enhancement Factor” or “k factor” derivation and rationale are unclear; testing of the proposed approach using the underlying study data to corroborate results should be confirmed.

EPA states in the TSD that the Pacsi *et al* study OGI captured approximately 80% of overall emissions, Method 21 (500 ppm leak detection threshold) captured 79% of emissions, and Method 21 (10,000 ppm limit) captured 65% of emissions, respectively. However, the Pacsi *et al* study is clear that even though using Method 21 identified more leaks (293 vs. 113 with OGI), the majority (67%) of additional leaks found were very small (1 scf/hr. or less). Further, both FID and OGI methods, while finding different leaking components, found a very similar total volume of emissions from leaking components at the site.

The Industry Trades disagree with EPA’s proposed “Enhancement Factor” or “k” factor. It seems that EPA has proposed the ”k” factor to account for both method’s quantification differences as well as other variables, such as the percentage of emissions found by survey methods (e.g., due to accessibility of components, etc.). Applying such logic to specific emission factors for specific equipment is not appropriate as the intent seems to include both updates for a specific leak factor for an individual component as well as capturing emissions from other components that may not be otherwise detected (i.e., the remaining 20% or 21% of emissions not directly identified by OGI or M21 respectively in the Pacsi *et al* study). Grossing up individual component emission factors is not a logical approach to account for leaks not directly identified. While the Industry Trades disagree in principle with EPA’s approach, if such an approach were to be applied, it would only be appropriate on an aggregate basis. That is, if EPA were to apply such logic, doing so as part of the National Inventory process would be more appropriate than grossing up emissions from induvial components or individual operators.

Additionally, and importantly, the Industry Trades have been unable to replicate the calculations EPA used to derive the “k” factors and request transparency regarding the approach and use of data relied upon by EPA prior to finalizing any rulemaking. The Industry Trades also request confirmation if EPA tested their “k” factors by applying to the M21 data in order to recalculate the emissions at site level using study data and confirm if it matches with the measured emissions.

3.10.4 Leak Duration

The leak duration should be revised to reflect a more reasonable and representative assumption that the leak duration is half the time since the last survey.

The leak duration associated with the Method 1 leaker emission factor approach should be half the time since the last survey. Assuming that the leak duration was the entire period since the last survey is an overstatement of the leak duration, as it implies the leak occurred on the date of the last survey which is unreasonable. Since the actual time the leak started is unknown, it is more reasonably accurate to assume that, on average, that the leak would have started in the mid-point of the survey cycle. This assumption accounts for that some leaks will occur before the mid-point and some will occur after the mid-point, but that on average, it is a reasonable assumption and much more representative than the conservative assumption that the leak started at the time of the last survey.

3.10.5 Method 3 – Default Population Emission Factors

The proposed population emission factor approach should be revised to improve accuracy of emission factors and component counts, while allowing more flexibility for reporters.

The Industry Trades are concerned that the Rutherford *et al* study (2021) used for the production and Gathering and Boosting emission factor development included infrequent large emitters in the derivation of the emission factors, including emissions from sources covered elsewhere and not considered fugitive components. Additionally, Rutherford *et al* didn't conduct any actual measurements of equipment leaks. The study results are a synthesis of past studies and includes storage tank emissions as fugitives. Given that EPA is now proposing to report large events as "other large releases," the Industry Trades believe using this study will result in double-counting. The Industry Trades support the use of the Pacsi *et al* and Zimmerle *et al* studies, despite EPA's concerns noted in the preamble regarding the smaller sample size. The Industry Trades believe the Pacsi and Zimmerle studies to be more appropriate for upstream and midstream operations.

The Industry Trades do not support the elimination of component count method 2 and request that EPA allow the use of actual component counts if it is subject to a state regulatory program that requires component counts.

3.10.6 Leak Detection at Onshore Gas Processing

Industry Trades generally support the updated definition of onshore natural gas processing that align with New Source Performance Standards as proposed in 98.230(a)(3). This update provides the regulated community with much needed alignment between regulatory programs and removed the confusion for reporting emissions under subpart W based on the previous definition included in the GHGRP.

However, the Industry Trades request that **CO_2 plants be included within the Onshore Gas Processing segment definition**, and not under the Gathering and Boosting definition.

Additionally, there are additional clarifications that are needed from EPA to the proposed equipment leak provisions as it pertains to onshore gas processing to better align with existing and proposed NSPS provisions.

The proposed use of NSPS OOOOb and EG OOOOc surveys for calculating emissions should be clarified and expanded.

EPA has proposed the following text at 98.233(q)(1)(vi)(F) to require the use of NSPS OOOOb and OOOOc survey data in calculating emissions from equipment leaks at onshore natural gas processing plants:

> *For an onshore natural gas processing facility subject to the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, each survey conducted in accordance with the equipment leak standards for onshore natural gas processing plants in § 60.5400b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter will be considered a complete leak detection survey for the purposes of calculating emissions using the procedures specified in either paragraph (q)(2) or (3) of this section. At least one complete leak detection survey conducted during the reporting year must include all components listed in § 98.232(d)(7) and subject to this paragraph (q), including components which are considered inaccessible emission sources as defined in part 60 of this chapter.*

Industry Trades recommend the following updates to this requirement:

- **Inclusion of alternate leak standards**: References to § 60.5400b should also include a reference to the alternate equipment leak standards in § 60.5401b to clarify that both OGI surveys conducted according to Annex K and Method 21 surveys with a 500 ppmv leak definition should be used in emission calculations.
- **References to the equipment leak standards under the earlier NSPS KKK, OOOO, and OOOOa** should be included so that survey data can also be used in emission calculations. While the earlier equipment leaks standards were for VOC only as opposed to the VOC and methane under NSPS OOOOb and EG OOOOc, some components in VOC service (>= 10 wt% VOC) may also be required to be surveyed under Subpart W (>=10wt% CH_4 + CO_2), and the monitoring technique in the earlier NSPS are already included in the approved list in 98.234(a). This update would allow operators to avoid potentially duplicative surveys.
- **The inaccessible component exemption should be retained under Subpart W.**[45] For onshore gas processing, the term "Inaccessible" has a long-standing meaning under NSPS, which historically is limited to connectors that are monitored using Method 21 with specific criteria that extends well beyond the 2-meter clause noted in 98.234(a). This exemption is directly linked to the safety of our personnel or the technical use of monitoring equipment. Specifically, connectors that are *"buried"* or that are "*not able to be accessed at any time in a safe manner to perform monitoring (Unsafe access includes, but is not limited to, the use of a wheeled scissor-lift on unstable or*

[45] EPA has proposed the following language per 98.234(a): Inaccessible emissions sources, as defined in 40 CFR part 60, are not exempt from this subpart. If the primary leak detection method employed cannot be used to monitor inaccessible components without elevating the monitoring personnel more than 2 meters above a support surface, you must use alternative leak detection devices as described in paragraph (a)(1) or (3) of this section to monitor inaccessible equipment leaks or vented emissions at least once per calendar year. For components located in the onshore production, natural gas gathering and boosting, transmission compression and underground storage (i.e. well sites, central production facilities, or compressor stations), the language proposed aligns with those that are identified at difficult-to-monitor when using M21 per the provisions in NSPS OOOOa and proposed NSPS OOOOb/c. The difficult-to-monitor components require annual monitoring under NSPS, which are consistent with the proposed language in 98.234(a). EPA could be consistent and use the term difficult-to-monitor if that was EPA's intent.

uneven terrain, the use of a motorized man-lift basket in areas where an ignition potential exists, or access would require near proximity to hazards such as electrical lines or would risk damage to equipment)" should not require additional leak detection provisions under subpart W.

3.10.7 Expand List of Approved Monitoring Technologies

The list of approved monitoring technologies should be expanded to include alternative periodic screening and continuous monitoring technologies.

Under proposed NSPS OOOOb and EG OOOOc[46], operators have the ability to use EPA approved alternative periodic screening or continuous monitoring technologies to satisfy the equipment leaks for well sites, centralized production facilities, and compressor stations. The Industry Trades have provided previous comments[47] on how to improve these proposed alternative technology provisions. Furthermore, results from alternative technology surveys could not be used for Subpart W emission calculations as proposed. Therefore:

- Operators would need to conduct an annual OGI or M21 survey for Subpart W for components subject to NSPS OOOOa/b/c or for other components if they elected to not use the population emission factors. This annual survey could be beyond what is required under NSPS.
- Results from use of alternate technology under NSPS OOOOb or EG OOOOc would be reported under large emissions release if thresholds were exceeded under Subpart W.

These two consequences would disincentive the use and development of alternate leak detection technologies. Therefore, 98.234(a) should be updated to include: "Periodic screening or continuous monitoring as specified in § 60.5398b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter…"

3.10.8 Component Applicability

The Industry Trades support EPA's proposal to exempt "components in vacuum service" from the equipment leak provisions in 98.233(q) and (r). These components have been historically exempt from the NSPS leak detection standard since no fugitive leaks are expected. However, we do not support inclusion of reporting requirements that include reporting of component counts for components in vacuum service.

3.11 Other Large Release Events

The Industry Trades support inclusion of a category of other large release events in Subpart W reporting requirements because these sources have been observed across many basins, and literature has demonstrated that they can have an outsized impact on total emissions. However, both the threshold and triggers for inclusion of an event based on credible information are problematic. Furthermore, in many cases it will double count emissions reported elsewhere in the regulation.

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[46] Proposed § 60.5398b and § 60.5398c.

[47] The Industry Trades have provided previous comments on how to improve these proposed alternative technology provisions. See Comment 3.0. https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428 https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-3819

3.11.1 Other Large Release Events Threshold

3.11.1.1 Instantaneous Rate of 100 kg/hr is Not a Meaningful Threshold

A threshold of an instantaneous rate of 100 kg/hr should be paired with a duration in order to ensure that the observation is, indeed, associated with a large release event. A measurement report of an instantaneous rate of 100 kg/hr should lead an operator to confirm whether or not such an observation was an indication of an ongoing large and otherwise unaccounted for event.

EPA explains that it "is proposing revisions to include reporting of additional emissions or emissions sources to address potential gaps in the total CH_4 emissions reported by facilities to subpart W."[48] "These revisions include proposing to add a new emissions source, referred to as ''other large release events,'' to capture large emission events that are not accurately accounted for using existing methods in subpart W."[49] An "other large release event" would be defined to include any event that exceeds an instantaneous methane emissions rate of 100 kg/hr or exceeds 250 mt CO_2e for the entire event.[50]

EPA further explains that the 250 mt CO_2e event-based threshold is based on a comparison to the Aliso Canyon event and other release scenarios that EPA considers to be objectively large. EPA asserts that the 100 kg/hr instantaneous emissions rate threshold is appropriate because it would "align with the super-emitter response program proposed in the NSPS OOOOb" and would "provide a means to get information for these large, shorter duration releases."[51]

The proposed reporting thresholds for "other large release events" are flawed for two reasons. First, EPA fails to provide any explanation of whether the reporting thresholds are appropriate or necessary for purposes of implementing the WEC. As explained above, the key purpose of the Proposed Rule is to provide information necessary for implementing the WEC. There are obvious questions that should be asked and answered by EPA as to how the type and scope of "other large release events" that would be required to be reported under the Proposed Rule squares with implementation of the WEC. EPA's views on the relationship between the proposed reporting thresholds and implementation of the WEC are necessary for EPA to fully assess the impact of the Proposed Rule and to allow for commenters to assess EPA's reasoning and provide informed input.

Since oil and gas emissions are highly variable in rate and duration, an instantaneous observation, even if extrapolated to provide results in units of an hourly emission rate as is typical, merely provides information regarding potential observations of far less than the represented hour in most cases. This is because an emission source with duration greater than 1 hour may have a variable rate over that hour or an emission source may resolve in far less than the hour. An instantaneous threshold of 100 kg/hr methane could result in numerous objectively small emission events (especially compared to an objectively large event release of at least 250 mtCO2e). An emission duration, assuming perfect observation and consistent emission rate of 1, 100, or even 1,000 times the <1 minute observation period for many technologies (assume 1

[48] 88 Fed. Reg. at 50284.
[49] Id.
[50] Id. at 50296.
[51] Id. at 50296-7.

minute here), would result in emission event quantities of 0.05, 4, or 42 mtCO2e or 0.02%, 2%, or 17% of the corresponding 250 mtCO2e threshold. In fact, it would take nearly 5 days of a constant emission rate of 100 kg/hr to accumulate emissions of 250 mtCO2e, of which there is no reasonable extrapolation of an instantaneous remote sensing emissions event.

Therefore, an instantaneous rate of 100 kg/hr is not a meaningful threshold to indicate that an emission source is large or even otherwise unaccounted, since multiple intended and accounted for emissions have transient large emission rates (blow downs, drilling completions, liquid unloadings, etc.). Such data should lead an operator to confirm whether or not such an observation was an indication of an ongoing large and otherwise unaccounted for event. emissions.

3.11.1.2 Other Large Release Threshold Needs to be Modified

If Other Large Releases Remain in the Rule, Modify the Threshold

At a minimum, the Industry Trades recommend that EPA modify the threshold for this category in 98.233(y)(1)(i) as follows (and modifying 98.233(y)(1)(ii) as applicable):

(i) For sources not subject to reporting under paragraphs (a) through (s), (w), (x), (dd), or (ee) of this section (such as but not limited to a fire, explosion, well blowout, or pressure relief), a release that~~either~~:

(A) Emits methane at any point in time at a rate of 100 kg/hr or greater; ~~or~~ **and**

(B) Emits combined GHG across the entire event duration of 250 metric tons of CO2e or more.

Requiring both thresholds be met would catch large releases discussed in the proposed rule's TSD, such as well blowouts, while also easing the burden on reporters to assess relatively smaller emission events, such as PSV releases that occur over a few seconds to minutes.

If EPA does not change the threshold as recommended below, the Industry Trades recommend that a duration of 100 hours be paired with the instantaneous rate of 100 kg/hr, which is commensurate with a duration at that emission rate that would result in 250 mtCO2e of

3.11.2 Detection Technology Must be Approved by the Super-Emitter Response Program

Furthermore, the Industry Trades are requesting that EPA clarify that the rate of 100 kg/hr is determined with only advanced detection technology and third parties approved by EPA through the SERP in NSPS OOOOb and not based on presumptive calculations, models, or ground sensors which have varying levels of uncertainty. Furthermore, if industry is not approved to use the technology for compliance with OOOOa, OOOOb, or OOOOc, the technology should not be required to be used for reporting purposes under Subpart W and used to determine fees under the WEC. Requiring this will discourage voluntary monitoring by companies, discourage new technology development, and include potentially highly inaccurate data to be the basis of the WEC.

3.11.3 Other Large Release Events Duration

EPA is proposing that reporters must assume a leak duration of 182 days if the start time of an event cannot be determined based on "monitored process parameters." EPA has no basis for using 182 days.

As noted in the proposed rule's TSD, typical durations for large releases are several hours to several days. The Industry Trades believe this 182-day assumption is derived using average leak duration data including a significant statistical outlier event[52] that should be excluded from calculated averages, most notably because the time it took to resolve the leak was not due to lack of awareness of the leak, but rather the complexity of resolving the leak. Accordingly, the Industry Trades disagree with EPA's statement in the TSD that the duration should not be shorter than the Aliso Canyon event. Besides it being a known event, EPA is proposing a default leak duration even longer than that statistical outlier event (111 days vs. 180 days).

The Industry Trades recommend a duration of half the time since the last optical gas imaging inspection, or the time since operator inspection of the source in question (e.g., operator rounds that proactively include flare, thief hatch or other inspections), site level measurement campaign, continuous monitoring system, or other monitoring data, or a maximum of 30 days if no other data is available. The maximum duration of 30 days is a conservative estimate consistent with (a) EPA's acknowledgement in the TSD that "Studies on large releases from oil and gas facilities commonly report that these emissions are intermittent, with typical durations of several hours to several days (Chen *et al*., 2022; Wang *et al*., 2022)", and (b) that most well sites are expected to have operator rounds occurring more frequently than every 30 days and, further, the odds of a significant event going unnoticed by both and operator and 3rd parties (satellite, etc.) are unlikely.

Furthermore, the Industry Trades believe that additional clarification and flexibility needs to be provided for "monitored process parameters." This is particularly critical for very short emission events for which telemetry may not be available or reliable. The Industry Trades are concerned that any ambiguity around this requirement could result in vast over-reporting of emissions by assuming a duration of 182 days. Monitored process parameters are not defined in the rule, but in 98.236(y)(4) EPA says that this includes "pressure monitor, temperature monitor, other monitored process parameter (specify)." The Industry Trades recommend clarifying this by allowing reporters to use additional process parameters, such as site inspections, cameras on location, etc. that confirm the event duration.

3.11.4 Credible Information

EPA is proposing that operators must report emissions from other large release events if they have "credible information" that a large release event has occurred. The Industry Trades are concerned that requiring reporters to use all credible information, especially where credible information in this context is ill defined, may disincentivize voluntary monitoring with emergent technologies where leaks could be discovered, but may have a large range of uncertainty (generally associated quantitative emissions estimates and short observational periods of less than 1 minute). Paradoxically, the shorter duration measurements tend to have higher accuracy in quantification for the short duration and the longer duration measurements tend to have emission estimating uncertainties that can span orders of magnitude. The Industry Trades recommend that EPA define "credible information" in a way to allows operators to use regulatory-driven inspections, allow for additional parameter monitoring while accounting for telemetry malfunctions, site inspections or camera monitoring, and engineering estimates to determine if a release has occurred and is subject to reporting.

[52] Underground storage station well blowout near Los Angeles, CA (i.e., Aliso Canyon) in 2015, event duration was 112 days as opposed to other events which were significantly shorter.

3.11.5 3rd Party Event Reporting

In 98.236(y), EPA is proposing that reporters must report any events identified through a potential super-emitter release. The Industry Trades urge EPA to implement guardrails around what and how a third-party could report, which is particularly impactful for those subject to SERP. Industry experience with third-party notification of suspected emissions events has demonstrated substantial variability in the quality and accuracy of those reports (including, but not limited to, data integrity, completeness, free from atmospheric interference, timing or greatly delayed notification, etc.). While the industry strives for excellence in reducing large release events, resources which would otherwise be utilized to minimize emissions could be diverted to respond to large volumes of unfounded third-party notifications which may have no basis in reality.

The proposed requirement to consider third-party release reports is beyond EPA's authority.

Additionally, the **Industry Trades request EPA to clearly define the scope of credible information that would trigger additional investigative and reporting burdens**. The Industry Trades are concerned that unqualified third-party reports developed by unqualified operators could unnecessarily increase the reporting burden while not leading to more accurate GHG reporting. The Industry Trades are requesting EPA to provide clear guidelines on who would be qualified to provide third-party reports and the associated duration of an observation necessary to trigger investigation and reporting obligations under Subpart W.

EPA proposes that third-party reports of "other large release events" submitted under NSPSSubparts OOOOb or OOOOc must be documented and addressed under Subpart W.[53] **API explained in its comments on the Subpart OOOOb and OOOOc proposed rules that EPA does not have authority to allow third parties to generate information that triggers regulatory requirements for affected/designated facilities.**[54] We incorporate by reference those comments here. Because the proposed third-party reporting requirements under Subparts OOOOb and OOOOc are beyond EPA's authority, those requirements should not be finalized and, by extension, should not be referenced or incorporated into the Subpart W provisions addressing "other large release events."

To begin, it is not possible to discern without further explanation from EPA who might constitute "another third party." That ambiguity makes it impossible to devise and submit informed comments on this aspect of the proposed reporting requirement.

Having said that, it is possible that EPA intends "another third party" to mean an entity submitting information to an affected facility outside of the third-party reporting provisions established under NSPS Subparts OOOOb or OOOOc. If that is the case, this aspect of the Proposed Rule is inadequate because EPA fails to explain the legal basis for imposing such requirements, including why such a requirement might be a reasonable under CAA § 114. Such a requirement would, in any event, be outside of EPA's CAA § 114 authority because CAA § 114 authorizes only EPA to collect information. It does not authorize EPA to impose a mandatory reporting obligation that would be triggered by third-party observations or

[53] 88 Fed. Reg. at 50433.
[54] API Comments on EPA's Proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review," EPA-HQ-OAR-2021-0317-2428 at 97-99.

assertions. If EPA believes that information about “other large release events” not reported pursuant to NSPS Subparts OOOOb or OOOOc should be reported by affected facilities, EPA must initiate the information request and may not rely on reports submitted by third parties.

Industry experience with third-party notification of suspected emissions events has demonstrated substantial variability in the quality (including data integrity, completeness, free from atmospheric interference, timing of or significant delay in notification, etc.) and accuracy of third-party reports. The Industry Trades may submit supplemental comments after the Oct. 2 deadline.

At this time, the term “credible” is not defined in this rule. The Industry Trades recommend that EPA adopt the Industry Trades recommendations for SERP, and 98.236(y) is modified to only include events which EPA deemed credible under the SERP, and modify the citation below as follows:

> *(y) Other large release events. You must indicate whether there were any ~~other~~ credible large release events from your facility during the reporting year and indicate whether your facility was notified of a ~~potential~~ credible super-emitter release under the provisions of § 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter. If there were any ~~other~~ credible large release events, you must report the total number of ~~other~~ large release events from your facility that occurred during the reporting year and, for each ~~other~~ credible large release event, report the information specified in paragraphs (y)(1) through (10) of this section. If you received a notification of a potential super-emitter release from a third-party for this facility or a super-emitter release notification under the provisions of § 60.5371b of this chapter or an applicable approved state plan or applicable Federal plan in part 62 of this chapter, you must also report the information specified in paragraph (y)(11) of this section.*

The Industry Trades are re-iterating our previously submitted comments regarding the credibility of those 3rd-parties reporting[55] as proposed in NSPS OOOOb. In short, the Industry Trades reiterate the importance that any third-party conducting these monitoring events should be certified by EPA to be included in the SERP.

In general, the Industry Trades are concerned that events reported under other source categories, such as “blowdowns,” thief hatches or equipment leaks could inadvertently be double counted under other large release events. The Industry Trades requests that EPA codify clear guidance on how to ensure that information reported by a 3rd party can be appropriately subtracted from events that could reasonably be reported under another category.

3.11.6 Other Concerns Regarding Other Large Release Events

The Industry Trades request that EPA remove the latitude/longitude reporting requirement proposed in 98.236(y)(11)(iii), and instead allow county-level reporting for pipeline release events (consistent with PHMSA requirements). If EPA maintains the requirement to report latitude and longitude of the release event, the Industry Trades request that EPA clarify that these events at sites other than pipeline locations may consist of a single latitude/longitude for a site (and should not include the granular latitude and longitude of the individual component).

[55] API Comments on NSPS OOOOb and EG OOOOc Supplemental Proposal letter, dated February 13, 2023. Section 1.1.

Furthermore, remote sensing technologies generally do not distinguish between emissions sources that are transient, included sources (blow downs, liquid unloadings, crankcase venting, etc.), or unintended sources that may or may not already be identified (unlit flares, over pressurized tanks, etc.) and thus there is a risk for double counting of certain emissions. Owner/operators should exclude sources that are already otherwise accounted for under another category, and EPA should explicitly allow exclusion of observations that could be classified as large emissions events but are otherwise already accounted for in another category.

To address one of EPA's requests for comments in the preamble, the Industry Trades believe that reconciling top-down data with bottom-up data should not force reporters to revise bottom-up estimates. The values recorded by these top-down sensors require significant data processing and analytics to provide the required measurement values, including concentration or flux. Moreover, even if the concentration (or concentration-pathlength) were perfectly accurate, error is introduced in post processing to produce estimates of emission rates, and these errors vary greatly depending on both the technology deployed, but even proprietary data treatment techniques between vendors of similar technologies. Beyond these uncertainties, however, is an inherent uncertainty introduced due to the temporal misalignment between the observational data and the bottom-up reporting methods. Not only do "matching" style reconciliation exercises require high spatial resolution of bottom-up emissions estimates (disaggregation to sites or even to the equipment level), but such exercises demand high temporal resolution. Otherwise, reliable extrapolation techniques must be applied to the often short duration observations to produce longer term emissions estimates. The aggregation of these uncertainties implies that the "top-down" measurements cannot be deemed more accurate, but simply useful in that they provide a different view of emissions.

3.12 Reporting Combustion Sources in Subpart C versus Subpart W

Emissions from natural gas combustion are *not* waste emissions that should be subject to the methane fee but are a result of the end use of natural gas within the value chain; emissions should be reported under Subpart C and not under Subpart W and excluded from methane fee calculations.

The Industry Trades appreciate that EPA intends to provide clarity on when reporters can use subpart C calculation methodologies instead of Subpart W, including defining the applicable gas quality. However, EPA has not provided sufficient information to justify the composition threshold of natural gas in determining between use of Subpart C or Subpart W calculation methodologies. EPA, in the TSD-W, concluded that the appropriate threshold criteria for use of subpart C includes a natural gas composition of 85% CH_4, but this threshold does not appear to represent any national or basin-wide average of the composition of fuel gas. EPA must provide additional information regarding the election of the 85% CH_4 composition threshold as a criteria for use of Subpart C methodologies.

As the Industry Trades previously commented during the June 2022 proposal, EPA should move all combustion calculations and reporting requirements from Subpart W to Subpart C to conform with the structure of the rule for other industries reported under the GHGRP. This would eliminate the current and proposed confusing structure that splits oil and gas combustion emissions across multiple subparts and references back and forth between the two subparts.

EPA seeks comment on "amending Subpart W to specify that all industry segments would be required to report their combustion emissions, including CH_4, under Subpart W to more accurately reflect the total

CH4 emissions from such facilities within the emissions reported under Subpart W." EPA asserts that Section 136(h) of the CAA specifies that EPA must "revise the requirements of subpart W…. [to] accurately reflect **the total CH_4 emissions and waste emissions** from the applicable facilities and allow owners and operators of applicable facilities to submit empirical emissions data, in a manner to be prescribed by the Administrator, **to demonstrate the extent to which a charge under subsection (c) is owed**" (emphasis added). Methane slip emissions from combustion are *not* waste emissions that are subject to the methane fee but are a result of the end use of natural gas within the value chain. Therefore, such emissions should be reported under Subpart C and not under Subpart W and excluded from methane fee calculations, when they are defined under future EPA rulemaking.

The IRA includes several statements that clarify the definitions of waste with regards to methane emissions within the rule. The IRA includes provisions for exemptions based on regulatory compliance with new source performance standards and state-level implementation of existing source rules that are equivalent or greater in emissions reductions to EPA's November 2021 Methane Rule framework. Neither the 2021 Methane Rule Framework nor the subsequent December 2022 proposal for NSPS OOOOb and EG OOOOc include source performance standards for methane slip from compressor engines. While not directly applicable to the methane fee, Section 50263 of the IRA clarifies that royalties on all extracted methane emissions on Federal lands and the Outer Continental Shelf have a stated exception for "gas used or consumed within the area of the lease, unit, or communitized area", which clearly would exempt the routine use of fuel gas, and associated methane slip emissions, from such royalty calculations. Considering these statutory provisions of the IRA, methane slip from compressor engines should not be included within the emission calculation framework for Subpart W and the eventual methane fee calculations that EPA will define at a later date.

3.13 Methane Slip from Incomplete Natural Gas Combustion

Direct measurement and the use of default equipment-specific destruction efficiencies should be allowed regardless of fuel type, and EPA should allow for control efficiencies from emerging technologies.

The Industry Trades agree with the agency that the default combustion efficiency for incomplete combustion or "methane slip" should be updated. However, it is important to note that the changes to methane combustion slip emission factors are expected to result in one of the largest changes to reported methane emissions, and EPA should allow the use of performance tests to determine methane slip factors regardless of fuel type. This would critically incentivize investments in technologies to reduce methane slip and would meet the objective of using empirical data. However, EPA should include these revisions under Subpart C instead of under Subpart W.

EPA's basis for exclusively using default equipment-specific destruction efficiencies, when the fuel does not meet at least 950 btu/scf, and contains less than 1% CO2 and at least 85% methane by volume is flawed. We recognize that EPA tried to simplify the performance test requirement to a one-time performance test, and as such did not propose to allow performance testing because fuel types "are expected to be highly variable in composition over the course of the year, such that a one-time performance test or OEM data are not expected to be representative of the annual emissions." The Industry Trades make two comments on this assertion. First, operator experience indicates that field gas is not significantly variable year over year and EPA does not provide data to support its assertion. Second, EPA does not explain why the range of any expected variability would result in a change in combustion slip. Third, and most importantly, reporters commonly conduct performance testing on engines to meet NSPS JJJJ/NESHAP ZZZZ or state regulatory requirements. As such, EPA should allow reporters to use those results regardless of the fuel gas type, as well as the default equipment-specific combustion efficiency for reciprocating internal combustion engines (RICE) and gas turbines (GT), as long as the performance test results are only applied to sites with similar fuel gas quality.

To further emphasize the importance of allowing performance test data from any RICE or GT, the Zimmerle study cited by EPA is representative for natural gas compressor stations, but it does not include any smaller engines likely to be found in an upstream environment. Allowing directly measured data will both provide EPA with additional details regarding methane slip related to the smaller engines, and it will allow operators to use empirical data as aligned with EPA's intent. Critically, this will also incentivize operational improvements to reduce methane slip from natural gas combustion. This also clears up the proposed discrepancy where EPA proposes to mandate incorporation of performance test results for some RICE and GTs, but prohibits the use of performance test results for others. Ultimately, there is no reason EPA should not allow operators to use results from periodic performance tests conducted per EPA reference methods regardless of fuel quality.

The table below summarizes the distribution of combustion efficiencies calculated from member-provided performance tests:

Horsepower	Count	Minimum Combustion Efficiency	Mean Combustion Efficiency	Median Combustion Efficiency	Maximum Combustion Efficiency
> 500 hp	76	96.16%	98.29%	99.46%	99.46%
< 500 hp	57	98.29%	99.58%	99.99%	99.99%

The above data is based on performance tests using engine horsepower, load, break-specific fuel consumption, the average grams of methane per horsepower-hour over three test runs, and the methane concentration of fuel gas. The combustion efficiencies were derived by dividing the stack test mass of methane by the mass of methane consumed in the fuel gas. The results show that minimum stack test combustion efficiency for engines greater than 500 horsepower is on par with EPA's equipment-specific default combustion efficiency for 4 stroke lean burn engines; while the combustion efficiency for engines less than 500 horsepower is greater than EPA's equipment-specific combustion efficiency for the same engine type. The data illustrates how smaller engines typically have favorable combustion efficiencies given they have smaller cylinder bores. The Industry Trades believe that allowing operators to develop horsepower-specific destruction efficiencies based on performance tests would lead to more accuracy while meeting EPA's intent to measure combustion slip from internal combustion units.

EPA should also allow for flexibility to incorporate methane controls as new technologies are being developed to control methane emissions from RICE. The Industry Trades recommend that EPA add a methane control efficiency parameter to Equation W-39B to allow for flexibility of incorporating a control efficiency to enable reporters to report methane slip more accurately when methane control technologies emerge and are demonstrated to be effective.

Allowing for the use of additional approaches to calculate methane slip from compressor engines would further support technology development. For example, the Department of Energy is currently in year two of funding for the ARPA-E REMEDY program (REMEDY | arpa-e.energy.gov) that has a stated goal of developing technical solutions to achieve 99.5% methane conversion in natural gas fired lean burn engines. If technology development from this 3-year, $35 million research program is successful, the ability to use updated values in methane emissions reporting could help to drive greater adoption of new technologies in operations.

3.14 Drilling Mud Degassing

In proposed Calculation Method 1, EPA is proposing to quantify drilling mud degassing by applying an emission rate derived from a representative well in the same sub-basin and at the “same approximate total depth.” The Industry Trades request clarification on how to determine the “same approximate total depth.”

EPA has proposed that operators must use mudlogging measurements taken during the reporting year, and therefore calculate emissions using Methodology 1. The Industry Trades disagree with this requirement, as it is possible a mudlogging measure is taken at the very early stages of a drilling operation, and that measurement may not ultimately be reflective of the entire duration of the drilling operation. The Industry Trades recommend allowing reporters to use Methodology 2 for all active drilling. The Industry Trades also propose a third option (see next comment), in the event that some mudlogging data is available.

The proposed third option would serve as a combination of the currently proposed Method 1 and 2. As stated above, this would allow operators to use a combination of the two methodologies when a varying level of directly measured data is available. In this third option, mudlogging measurements would be used based on Method 1 for the period in which the data is available, and Method 2 would be used for the remaining period of drilling activity where mudlogging data is not available. This method should also allow operators to account for drilling mud degassing vapors sent to a control device.

EPA is proposing to calculate emissions from drilling mud degassing based on the total time that drilling mud is circulated in the representative well. The Industry Trades request that EPA clarify that this should be calculated based on circulating time in the hydrocarbon bearing zones only (i.e., excluding surface holes drilled by a spudder rig when no hydrocarbons are present).

One further complication of the proposed method for quantifying methane emissions from drilling mud degassing is that the concentration of natural gas (or methane) in drilling mud is not currently specifically measured and is difficult to obtain. Further, it is not measured by mud loggers in units of ppm, as the measurement instrument used is in units that are not representative of methane concentration.

3.14.1 Proposed Calculation Method 2

EPA is proposing the following emission factors in MT CH4 per drilling day for drilling mud degassing: 0.2605 for water-based drilling muds, 0.0586 for oil-based drilling muds, and 0.0586 for synthetic drilling muds. The EPA based these factors on a study evaluating emissions from offshore drilling from 1977, which is both outdated, and not representative of most onshore drilling operations in the United States. Furthermore, these outdated factors are based on mud throughput, but the basis remains unclear. The Industry Trades reiterate that the emission factors compiled in the 2021 API Compendium for Well Drilling and mud degassing (Section 6.2) is appropriate for the well bore and porosity conditions for onshore drilling operations as it was developed specifically for onshore operations. Use of the proposed offshore emission factors for onshore drilling operations will significantly overstate methane emissions from onshore production mud degassing. The Industry Trades suggest that the emission factor should be derived as a function of well dimensions to better represent mud degassing emissions. Otherwise, the Industry Trades recommends that proposed methodology 2 be revised based on drilling time in hydrocarbon hole section, and not overall event days. There can be multiple days in a hydrocarbon hole section where the pumps are not circulating.

3.14.2 Reporting Requirements

Reporting requirements proposed in 98.236(dd) require reporting total vertical depth of the well, and the circulation time of the drilling mud within the wellbore. The Industry Trades do not support reporting this information, as EPA did not address why the information would be requested. Furthermore, total vertical depth would not provide representative information for horizontal wells and would not improve the reported data quality.

3.15 Crankcase Venting

In general, the Industry Trades support the use of actual test data for crankcase venting when available, while still allowing the use of a provided emission factor. However, the Industry Trades believe the emission factor for this activity should be derived based on horsepower in order to be more reflective of operations in the onshore production or gathering and boosting segments, should include the ability to take credit for routing the emissions to a control device, and do not believe this emission source category should include gas turbines. The study cited in the TSD included an audit of three gas compressor stations and two natural gas storage sites[56]. These facilities are expected to have a much higher vent rate than in production operations due to the larger engine size required in gas compressor stations and gas storage. Therefore, the proposed average emission factor may reflect an overestimation of this source for upstream production and many smaller gathering and boosting facilities. The Industry Trades suggest that EPA considers deriving an emission factor based on engine horsepower instead of vent count, as the vent rate is correlated with engine size rather than number of vents.

As proposed, there is no method to reflect reductions if emission controls are developed and implemented or crankcase venting is routed to a control or combustion device. The Industry Trades recommend adding this flexibility by including a control efficiency parameter in Equation W-45, which also has the added impact of incentivizing controls where feasible.

The Industry Trades also recommend that EPA provide clarification around how to account for crankcase vents which are manifolded together, as the reporting requirements are on a per-vent basis.

EPA is proposing a reporting requirement for the average operating hours for each reciprocating internal combustion engine or gas turbine. The Industry Trades recommend the removal of this “average” data; it is duplicative and requires operators to average numbers used in calculations for the sole purpose of reporting this element. The Industry Trades recommend removing this data reporting requirement or leaving the reporting requirement on a per-site basis of total operating hours.

[56] Johnson *et al.*, 2015

Additionally, the factor prescribed by EPA is based on an API study,[57] which only represents reciprocating engines, and not natural gas turbines. The study's definition of crank case is, "The crank case on *reciprocating engines* and compressors houses the crank shaft and associated parts, and typically an oil supply to lubricate the crank shaft…"[58] (emphasis added). The study also only referred to reciprocating engines later in the document, "Additionally, *reciprocating engines* crankcase vents were checked for significant blow-by (i.e., leakage past the piston rings into the crankcase) because blow-by reduces cylinder compression that causes inefficient operation and contributes to unburned and partially burned fuel emissions[59]" (emphasis added). There is no mention anywhere that natural gas turbines were evaluated as a part of this study.

Since the definition of crankcase within this study explicitly states that it is only applicable to reciprocating engines, and the body of the text supports that definition, then natural gas turbine crankcase vents were not evaluated as part of this study. It is arbitrary to use 2.28 scf/h per crankcase vent for natural gas turbines because turbines were not evaluated for this study.

Natural gas turbines are inherently different from reciprocating engines and quantifying crankcase venting in the manner proposed does not make sense.

A reciprocating engine is a cyclic operation by nature - the piston is required to stroke back and forth inside the cylinder to complete four primary process strokes: intake, compression, power, and exhaust. The piston moves back and forth inside the cylinder of a reciprocating engine, using the piston rings to seal process gas inside the cylinder during the combustion process. This piston is connected to the crankshaft, which translates the reciprocating movement from the combustion in the cylinder to rotational movement at the output shaft. Any leakage across the piston rings will result in combustion gas in the crankcase, which needs to be vented to avoid condensation, contamination, and ongoing reliability concerns. The piston rings act as a primary seal between the combustion process and the atmosphere, and the crankcase takes on the role of a rudimentary "capture" system.

Gas turbines operate using a completely different mechanical method. There is no cyclic or reciprocating element to a gas turbine operation (no piston, piston rings, or crankcase). A gas turbine uses one (or more) rotating shafts to continuously complete all four primary combustion functions inside the gas turbine casing: intake, compression, combustion, and expansion. Since the shaft(s) are already rotating as part of the combustion process, there is no requirement to have a translation from reciprocating to rotational movement, so there is no crankshaft or crank casing to be vented. Combustion gases are ultimately routed to the atmosphere by way of the exhaust duct once the power turbine has extracted the energy. The potential leakage points for combustion gases would be at the turbine casing flanged connections or at the shaft seals, which are addressed by other parts of this rulemaking (fugitive emissions).

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[57] Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites. EPA Phase II Aggregate Site Report prepared for U.S. EPA Natural Gas STAR Program by Natural Gas Machinery Laboratory, Clearstone Engineering Ltd., and Innovative Environmental Solutions, Inc. March 2006. Available at https://www.epa.gov/sites/default/files/2016-08/documents/clearstone_ii_03_2006.pdf and in the docket for this rulemaking, Docket Id. No. EPA–HQ–OAR–2023–0234.
[58] Page 14 of 74 of API study.
[59] Page 40 of 74 of API study.

The Industry Trades propose that natural gas turbines not be included for reporting crankcase venting, as there are no crankcase vents on the natural gas turbines.

3.16 Gathering and Boosting versus Production Site Categorization

EPA is considering significant changes in its reporting requirements for the various industry segments in the rule. One of the key changes involves designation of upstream operators' centralized tank batteries that EPA has named "centralized oil production sites." These are defined as sites collecting oil from multiple well pads without compressors "that are part of the onshore petroleum and natural gas gathering and boosting facility." In the proposed rule, EPA has classified centralized oil production sites under the gathering and boosting segment.

The Trades appreciate that EPA has recognized centralized production sites as a facility type in the proposed rule. However, there are challenges and environmental disincentives with including "centralized oil production sites" in the gathering and boosting segment, especially when viewed through the lens of the upcoming waste emissions charge.

First, EPA included "production" clearly in the name and it is nonsensical that centralized production sites would be considered part of the gathering and boosting segment. These sites perform many of the same functions as the traditional well pad only production facilities (which are included in production), but reduce the overall environmental footprint associated with oil and gas development included emissions reductions and minimizing surface use by flowing multiple wells into on pad.

Next, EPA's proposed definitions are contrary to IRA's MERP waste emissions thresholds, where gathering and boosting sites are considered "non-production." In the MERP language, (f) Waste Emission Threshold, Congress created two categories for applicability of the threshold: "Production" and "Non-Production." The Gathering and Boosting segment (segment #8) is explicitly listed under "Non-Production." Clearly Congress did not intend for sites associated with production, such as "centralized production sites" to be considered gathering and boosting. EPA may have been able to impose reporting obligations for emissions from centralized tank batteries under the gathering and boosting segment in the past but for application of the fee, these sites should be considered production. Doing otherwise would result in an inequitable application of the fee that would most likely not be applied uniformly by all upstream operators.

EPA's proposal to group its proposed new definition of "centralized oil production site" within the "gathering and boosting" category, *see* 88 Fed. Reg. at 50,437/1, is inconsistent with the text and structure of CAA § 136. Congress defined "production" and "gathering and boosting" as two distinct items in a list of eight parallel categories of applicable facilities subject to the MERP charge, CAA § 136(d)(2) ("Onshore petroleum and natural gas production"), (8) ("Onshore petroleum and natural gas gathering and boosting"). EPA is therefore acting contradictory to this text and to Congress's intent when it proposes to categorize *production* facilities as *gathering and boosting* ones. And this mis-categorization will have consequences, because the waste emissions threshold above which a charge will be imposed on applicable facilities' emissions differs between these two categories, *see id.* § 136(f)(1), (2

The proposed definition of "centralized oil production site" is also inconsistent with the proposed definition and regulatory treatment of a "centralized production facility" in the pending CAA § 111 methane standards proposal for both new and existing sources.

In addition, the categorization of a centralized production site into gathering and boosting could result in a backslide from the progress industry has made in minimizing its overall footprint and emission sources. Due to the higher methane fees that may accompany categorizing production sites as gathering and boosting (subjecting these facilities to the 0.05% threshold instead of the 0.2% threshold) operators may be economically incentivized to migrate back to individual well pad installation dramatically increasing the amount of equipment in the field, increasing GHG emissions, and increasing surface use.

Further, these sites are considered by many operators as part of the upstream production process as these tank batteries are likened to "production supportive facilities." Many operators have migrated to more centralized production facilities in an effort to reduce the overall environmental footprint. As opposed to midstream operators that traditionally operate gathering and boosting sites downstream of a custody transfer meter that are typically large compressor stations that boost gas across an area, the sites in question are a less impactful way of separating and storing fluids from multiple wells and providing efficient compression for artificial lift. Facility design efficiency gains over the years have led to centralization of production surface equipment. The centralization of surface equipment typically results in emissions reductions relative to dispersed facilities (separation and tanks installed at each well pad) because the total equipment counts are significantly reduced (fewer emission points), there is a reduction of tank batteries/spill risk, increased operational efficiencies, and better ability to site major facilities away from sensitive areas/populations. This segment classification is contradictory to previous interpretations and may have unintended consequences such as companies electing not to centralize such operations due to the more burdensome methane fee implications. Facilities comprised of centralized surface equipment are owned and operated by producers, are considered in the industry as part of production, and may or may not include a well head or pump jack collocated on a single pad.

However, because EPA re-defined the production segment in 2016 as "associated with a single well pad" this has created a great deal of confusion with reporters and centralized tank batteries have been categorized differently both by individual owners / operators, as well as other federal rules (NSPS OOOOb). For example, under the proposed OOOOb/c regulations, the "centralized oil production facilities" (referred to in NSPS OOOOb as "centralized production facilities") are grouped under the production segment by definition, not gathering and boosting as explained below:

> *Currently, in Subpart W "Centralized oil production site means any permanent combination of one or more hydrocarbon liquids storage tanks located on one or more contiguous or adjacent properties that does not also contain a permanent combination of one or more compressors that are part of the onshore petroleum and natural gas gathering and boosting facility that gathers hydrocarbon liquids from multiple well-pads. A centralized oil production site is a type of gathering and boosting site for purposes of reporting under §98.236."*

While NSPS OOOOb/c has a different name and definition of this as follows:

> *"Centralized production facility" means one or more storage vessels and all equipment at a single surface site used to gather, for the purpose of sale or processing to sell, crude oil, condensate, produced water, or intermediate hydrocarbon liquid from one or more offsite natural gas or oil production wells. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and flowline. Process vessels and process tanks are not considered storage*

vessels or storage tanks. A centralized production facility is located upstream of the natural gas processing plant or the crude oil pipeline breakout station and is a part of producing operations."

In addition, in the Pipeline and Hazardous Material Safety Administration's ('PHMSA") proposed Gas Pipeline Leak Detection and Repair rule, PHMSA does not define or regulate any production facilities as "gathering and boosting." Specifically, as defined in API's Recommended Practice-80 and incorporated in 49 CFR 192:

> *"The production function, in most cases, extends well downstream of the wellhead and may include several processes required to prepare the gas for transportation. 'Production Operation' means piping and equipment used for production and preparation for transportation or delivery of hydrocarbon gas and/or liquids and includes the following processes: (a) extraction and recovery, lifting, stabilization, treatment, separation, production processing, storage, and measurement of hydrocarbon gas and/or liquids; and (b) associated production compression, gas lift, gas injection, or fuel gas supply."*

Both the NSPS OOOOb/c and PHMSA's name and definition of what are essentially tank batteries are much more consistent with how these facilities operate and are managed in the field. To mitigate confusion and create more rule alignment, the Industry Trades suggest that EPA align the name and definition of the subject facility type between Subpart W and NSPS OOOOb/c.

In this proposal, EPA claims to be striving for consistency when EPA states, on page 50288 of the proposal,

> *"as in the 2016 rule, the proposed amendments would also allow facilities to use a consistent method to demonstrate compliance with multiple EPA programs." Also, the Trades note that even though EPA uses the word "gather" in the definition in Quad Ob/c, these sites are still properly defined as "part of the producing operations."*

Further, the fact that EPA has proposed the definition of "centralized production sites" as sites that do not include compressors that are part of the gathering and boosting segment is puzzling. If these sites are part of the gathering and boosting segment as EPA has proposed, why would these sites not be allowed to have compressors that are part of the gathering and boosting segment on them? This demonstrates that EPA possibly does understand the distinction between gathering and boosting compressors that should appropriately be included in the gathering and boosting segment and centralized tank batteries that clearly should not.

As such, The Industry Trades request that EPA change both the name and definition of "centralized oil production site" in the Subpart W rule to match NSPS OOOOb and EG OOOOc to align with other federal programs under production (not gathering and boosting) for consistency and to reflect how the industry owns and operates these facilities. The Trades also strongly recommend that EPA delete "associated with a single well pad" from the Onshore Petroleum and Natural Gas Production definition in Subpart W in order to clear up the confusion and properly have centralized production sites in the production segment where they belong.

3.17 Need for EPA to Include Pathways for Other Types of Empirical Data

For many source categories under Subpart W, the Trade Industries appreciate that EPA has included several options for operators to be able to provide empirical data, such as measurement with metering or using updated emissions factors based on recent field measurement studies. However, under this proposed rule, EPA has not included a pathway for using the results of advanced methane detection and measurement surveys as a source of empirical data for key source categories, like tanks, flares, and compressors.

Methane detection and measurement technologies have advanced in the last few years due to early-phase research efforts, including from the Department of Energy, to develop technologies that have now become commercially available. As API shared with EPA during the NSPS OOOOb and OOOOc rulemaking, many operators have included these technologies in their voluntary methane management programs, including the use of quantitative aerial technologies at more than 8,000 sites. Many of these systems provide quantitative information that, when paired with other operational sources of data, provide empirical information about methane emissions from assets. Including a pathway for utilization of these technologies for emissions reporting would improve the quality of data submitted under Subpart W while supporting a growing methane detection and measurement industry. **A final rule for changes to Subpart W should include a pathway for utilizing survey results from technologies, particularly those approved for use under NSPS OOOOb and OOOOc, for emissions reporting.**

4. Administrative Recommendations

4.1 Streamline Existing Reporting Forms to Reduce Duplicative Reporting and Reduce Unnecessary Submittal Errors

Due to the proposed requirement to report information on a more granular basis, the Industry Trades recommend the following streamlining efforts to reduce duplicative reporting, and to reduce the possibility of administrative error.

1. EPA should provide industry with a draft of the eGGRT form for review ahead of the reporting season (prior to January 1, 2026). The Industry Trades are concerned that the site-by-site reporting could cause these files to become very large and difficult to transmit and/or store.
2. EPA has not indicated how Best Available Monitoring Methods (BAMM) will be allowed for the newly proposed sources. The Industry Trades reiterates the need for ample implementation time.
3. Remove all requirements to report a count of equipment or events when there is a requirement to report on an equipment- or site-level basis. Requiring a count of an item that is already provided on a line-by-line basis does not improve the reported data quality, does not increase EPA's ability to validate the reported data, and introduces potential errors that will flag unnecessary follow between reporters and EPA.
4. Remove or automate Table AA.1.ii on Tab (aa)(1). All the required information is reported in Table AA.1.iii. By repeating this information in Table AA.1.iii, it increases the possibility of data errors while not improving data transparency.
5. Remove detailed reporting elements on Tab (aa)(1) in Table A.1.iii, as the detailed information on a well-by-well basis is already included on the respective source tabs (and proposed additional sources as part of this rulemaking):
    a. Well venting for liquids unloading;
    b. Completions or workovers with hydraulic fracturing;
    c. Completions or workovers without hydraulic fracturing;

   d. Well testing; and
   e. Associated gas venting and flaring.
6. Miscellaneous Topics
   a. Reporting condensate separate from other hydrocarbon products will be challenging due to where and how it is separated.

5. Rule Implementation

EPAs plans to finalize the rule in August 2024, with an implementation date of January 1st, 2025. The impractical tight timeframe to implement the final rule places an unrealistic expectation on reporters, especially given that (as proposed) they will have to install new equipment and develop inspection programs to comply with the rule. The impracticality of the proposed timeline is further exacerbated by the persistent supply chain shortages operators are experiencing for critical equipment necessary to comply with the proposed NSPS OOOOb, as the Industry Trades have described to EPA.[60] Primarily, the Industry Trades reiterates its position that measurement, sampling and monitoring requirements should not be included in the GHGRP itself. However, should any measurement, sampling and monitoring requirements be codified in Subpart W for sources not required to comply with other regulatory programs, EPA should allow for a phase-in period (as it did during the first two years of Subpart W implementation) to allow for reporters to incorporate those requirements.

6. Conclusion

The undersigned associations, representing the oil and natural gas industry, appreciate EPA's willingness to collaboratively engage with the regulated community in order to improve the quality and consistency of reported data while also streamlining the reporting process. The comments provided in this letter are intended to support this effort by providing EPA with additional context and potential unintended consequences associated with some of the proposed measurement, reporting, recordkeeping, and quality assurance/quality control requirements.

The Industry Trades support the goal of reducing GHG emissions across the value chain of the oil and natural gas industry, and it is critical that the EPA and the GHGRP reflect accurate reporting of GHG emissions. To that extent, it is important that EPA carefully consider these proposed revisions and new subparts and consider the points outlined by the Industry Trades while considering future proposed rulemaking.

The undersigned associations encourage EPA to carefully consider the comments and recommendations contained within this letter. We stand ready to respond to any questions and provide further clarifications, as needed, from EPA. Please do not hesitate to contact any of the undersigned or API's Jose Godoy, Climate & ESG Policy Advisor, at godoyj@api.org.

Sincerely,

[60] https://www.api.org/news-policy-and-issues/letters-or-comments/2023/09/20/API-Letter-to-EPA-Administrator-Regan-on-EPA-Methane-Rule.

Aaron Padilla
Vice President, Corporate Policy
American Petroleum Institute

Wendy Kirchoff
Vice President, Regulatory Policy
American Exploration & Production Council

C. Jeffrey Eshelman, II
President & Chief Executive Officer
Independent Petroleum Association of America

Angie Burckhalter
Sr. V.P. of Regulatory & Environmental Affair
The Petroleum Alliance of Oklahoma

Leslie Bellas
Vice President
American Fuel & Petrochemical Manufacturers

CC: Chris Grundler, Director for Office of Atmospheric Programs, EPA
Mark DeFigueiredo, Office of Atmospheric Programs, EPA

ANNEX A: API Study, "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States.

Note: Data for this study is included separately within this docket in excel format.

Memorandum

Date: July 2, 2020

To: Mark DeFigueiredo, Melissa Weitz, Adam Eisele

Climate Change Division, U.S. Environmental Protection Agency

From: Karin Ritter, Manager, Corporate Policy, American Petroleum Institute

Re: American Petroleum Institute Pneumatic Controller Measurement Study

The American Petroleum Institute (API) is pleased to provide the results of the API Field Measurement Study of Pneumatic Controllers and API's proposal for a two-tiered emission factor for controllers. Paul Tupper (Shell), on behalf of API, presented preliminary information from this study at the Stakeholder Workshop on GHG Data for Natural Gas and Petroleum Systems held in Pittsburg PA on November 7, 2019. This was followed with an API and EPA conference call on January 13, 2020 where API provided answers to EPA's questions regarding the study results and details (attached).

As a reminder, the API field study found that the average emission rate for properly functioning intermittent controllers was 0.28 scfh, 24.1 scfh for malfunctioning intermittent controllers and an overall average emission rate for all intermittent controllers of 9.3 scfh. Continuous low bleed controllers had an average emission rate of 2.6 scfh and continuous high bleed controllers 16.4 scfh. Malfunctioning intermittent pneumatic controllers measured in the API study account for about 85% of observed pneumatic controller emissions, from all controllers measured, and 98% of the observed intermittent pneumatic controller emissions. About 38% of the intermittent pneumatic controllers in the study were determined to be malfunctioning although a small subset of the malfunctioning controllers contributed the bulk of measured emissions.

The results of the API field study pneumatic controller measurements are consistent with prior studies (Allen et al. 2015, Thoma et al. 2017) which found that a small number of malfunctioning intermittent controllers accounted for the bulk of pneumatic controller emissions measured. Based on the results of the API study, API proposes that EPA modify 40 CFR Part 98 Subpart W to include a two-tier intermittent pneumatic controller emission factor option for intermittent pneumatic controllers that are included in a qualified inspection and repair program. This would be similar to the leaker emission factor option currently in Subpart W for equipment leaks. Specifically, API is proposing a properly functioning intermittent pneumatic controller whole gas emission factor of 0.28 scfh, and a malfunctioning intermittent pneumatic controller emission factor of 24.1 scfh. These emission factors would be applied to intermittent pneumatic controllers included in a qualified inspection and repair program. Intermittent pneumatic controllers not included in a qualified inspection and repair program would continue to use the current emission factor of 13.5 scfh. A qualified inspection and repair program would require instrument (optical gas imaging (OGI)) inspection of intermittent pneumatic controllers on a minimum annual frequency to determine whether they have continuous emissions which would indicate that they are malfunctioning. The tiered emission factor could be used by operators that voluntarily include intermittent pneumatic controllers in an inspection and repair program or that are required to include them by regulation or other requirement. Such an approach would enable demonstration of emission reductions by operators who are voluntarily conducting pneumatic controller inspections and repair and potentially incentivize further voluntary inspections to identify malfunctioning pneumatic controllers. It would also improve the accuracy of emissions reported into the Greenhouse Gas Reporting program for intermittent pneumatic controllers and ultimately could be used to improve the accuracy of estimated emissions in the Greenhouse Gas inventory. API is not proposing any changes to the emission factors for continuous bleed controllers at this time.

API notes that OGI inspection of intermittent pneumatic controllers to determine if they are properly functioning or malfunctioning is the technique used by EPA and the Colorado Department of Public Health and Environment (CDPHE) in their recently published study "Understanding oil and gas pneumatic controllers in the Denver–Julesburg basin using optical gas imaging". API also suggests that EPA may wish to include data from prior studies (Allen et al. 2015, Thoma et al. 2017) to calculate a set of tiered emission factors from a wider dataset.

Enclosed with this memo are an API paper titled "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States", an excel file with data tables for the study, and API's responses to EPA's questions received prior to the January 13, 2020 conference call. Should you have any questions regarding this study or API's tiered emission factor proposal please feel free to contact me.

Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States

Introduction

EPA's current Greenhouse Gas Reporting Program (GHGRP) emission factor for natural gas-driven intermittent vent pneumatic controllers represents an average emission rate of 19 pneumatic controllers, 7 measured in the US and 12 measured in Canada during two field campaigns in the 1990's (EPA, 1996). The 7 US pneumatic controllers had an average emission rate of 21.3 standard cubic feet per hour (SCFH) with a range of 8.8 to 39.6 SCFH. The 12 Canadian pneumatic controllers had an average emission rate of 8.8 SCFH with a range of 0.5 to 29.0 SCFH. Combined, these 19 intermittent pneumatic controllers had an average emission rate per intermittent pneumatic controller of 13.5 SCFH. The small total sample size (19 measurements) and high variability of the measurements suggests that the EPA mandated average emission factor of 13.5 SCFH warrants reevaluation.

Several pneumatic controller emissions studies conducted since then have focused on emission factor development or comparisons with existing factors based on field observations (Allen et al. 2013, Allen et al. 2015, Thoma et al. 2017, Prasino Group 2013). These studies observed a skewed distribution of emissions largely related to emissions from intermittent pneumatic controllers with higher than expected emissions for properly functioning controllers. Allen et al. (2015) found that 95% of observed emissions were attributable to 19% of pneumatic controllers and noted that the majority of the 40 highest emitting controllers were behaving in a manner inconsistent with manufacturer design. Thoma et al. (2017) also concluded that emissions were dominated by malfunctioning pneumatic controller systems, although the absolute emission rates observed were lower than with Allen et al.

The American Petroleum Institute (API) conducted a pneumatic controller measurement study between June and April 2016. Study goals included creating a pneumatic controller inventory for the regions surveyed, classifying pneumatic controllers, understanding the frequency of pneumatic controller malfunctions, and quantitatively measuring emission rates. The analysis presented in this report focuses on the quantitative measurements of intermittent vent pneumatic controllers, where the controllers are sub-classified as either properly functioning or malfunctioning intermittent pneumatic controllers. Emission factors are derived by sub-category, akin to the leak emission factor for fugitive components (US EPA, 2017). Overall, malfunctioning intermittent vent pneumatic controllers measured in the API study account for about 85% of observed pneumatic controller emissions and 98% of the observed intermittent vent pneumatic controller emissions.

Materials and Methods

Pneumatic Controller Inventory

Pneumatic controllers were inventoried at 67 sites[1] operated by 8 companies, across a variety of site types in the production and gathering and boosting segments of the oil and natural gas sector. The sites represented a variety of production and formation types, including conventional and unconventional oil and gas plays, across four basins as defined by the American Association of Petroleum Geologists (AAPG): Anadarko (AAPG Basin 360), San Juan (AAPG Basin 580), Gulf Coast (AAPG Basin 220), and Permian (AAPG Basin 430). Pneumatic controllers from these sites were inventoried and classified as either continuous high bleed, continuous low bleed, or intermittent vent pneumatic controllers based upon a combination of manufacturer information, manufacturer technical data sheets, and expert judgement.

Pneumatic Controller Emissions Measurements

Emission rate measurements were collected for controllers at 39 of the 40 sites with natural gas powered pneumatic controllers. For each measured pneumatic controller, the emission rate of whole gas was quantified using a high-volume sampler instrument (see description below). Whole gas emission rates were calculated based upon concentration, flow and equipment-specific hydrocarbon response factors developed from site-specific gas compositions, as provided by participant companies. In some cases, site-specific gas compositions were unavailable. AAPG basin average concentrations were developed from the available site-specific concentrations and applied to those sites in the same basin without site-specific gas concentrations.

Development of the specific instrument configuration and gas composition correction factors were recently described and applied in a companion study that compared the effectiveness of Method 21 and Optical Gas Imaging for monitoring of fugitive components in oil and natural gas operations (Pacsi et. al, 2019). In this study, a custom GHD recording high volume sampler, developed by GHD – the contractor preforming this study, was used for most pneumatic controller measurements. The GHD recording high flow sampler is a modification to the original high flow samplers developed by Indaco. These modifications include the use of a data logger to record the sample flow and the sample gas concentration at approximately 1/2Hz. Due to instrument availability, there were 8 instances where an Indaco high volume sampler was used for the pneumatic controller measurement and one instance where the Bacharach high volume sampler was used. Three of the 9, measured with the Indaco or Bacharach high volume samplers, had zero measured emissions, while the remaining six measured constant emission rates.

Sampling, over an approximate 15-minute period, occurred through a nozzle affixed to a sampling bag. The sampling bag was fitted over the emission point of the pneumatic controller allowing ambient air to comingle with the source emissions. The recording high volume sampler was equipped with a pump which pumped ambient air and hydrocarbons from the emission point through the nozzle to the flow

[1] Five sites in the Permian Basin were not inventoried due to being primarily CO_2 or instrument air for the pneumatic controller supply gas.

meter and concentration detection instrument. The combustible gas concentration instrument, a Bascom-Tuner Gas Rover, measured combustible gas concentrations via one of two detectors: either a combination catalytic oxidation (0-5% hydrocarbon gas) or a thermal conductivity (5-100% hydrocarbon gas) detector. Further information on the instrument detail is available in the Supplemental Information from the companion equipment leaks study (Pacsi et. al, 2019) and references such as Lamb et al. (2015) and Thoma et al. (2017).

Properly functioning intermittent vent pneumatic controllers have near-zero emission rates between actuation cycles. Also, the volume of vented gas associated with controller actuations can vary widely from pneumatic controller to pneumatic controller. With the wide variation of emissions and high frequency of non-detect measurements in this and prior pneumatic controller measurement studies, it was prudent to develop a conservative field detection limit estimate for this study to facilitate appropriate interpretation of zero or near zero field measurements. The instrument methane detection limit for the GHD recording high volume sampler was determined to be 0.009 SCFH based on the lowest flow recorded during pneumatic controller testing and the methane detection limit of the Bascom-Turner Gas Rover (50 ppm) used in the GHD recording high volume sampler. However, in field use the instrument resolution was coarser than the instrument's minimum detection limit.

The GHD recording high volume sampler instrument operates with variable flow rates. Accordingly, the instrument detection thresholds and instrument resolution varied over the course of the study in terms of resolvable emissions rates since both the emission rate detection limit and instrument resolution is a function of measurement flow rate. An effective resolution for each non-zero time series was calculated as the minimum of the absolute value of the differences between adjacent elements of a given time series. This represents the minimum measured emission rate difference from one measurement to the next in each time series. The derived minimum effective resolution provided an estimate of the minimum resolvable emission rate for this study.

Figure 1 shows the effective resolutions for 127 of the time series measurements (non-zero time series for intermittent vent pneumatic controllers that varied over the course of the approximately 15 minute measurement). The median value of effective resolution for the 127 time series measurements is 0.26 SCFH, with approximately 70% of the measurements having an effective resolution between 0.2 and 0.35 SCFH. Therefore, an effective resolution over the course of the study was empirically determined to be 0.26 SCFH.

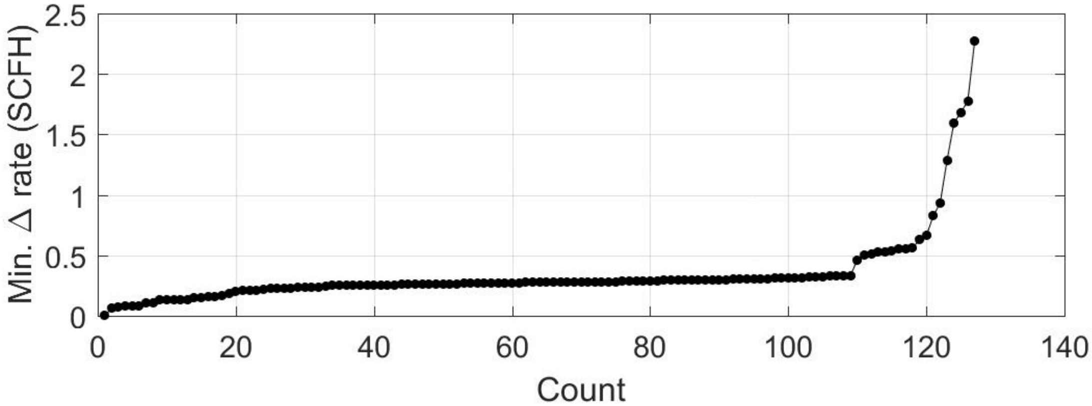


Figure 1: Instrument resolution step sizes for the recorded time series.

Approximately 45% of measured emission rate values of the intermittent vent pneumatic controllers were less than half of the effective resolution, and a large number had zero measured emissions. Thoma et al. (2017) previously described a "seepage rate" assumed to be on the order of 0.05 SCFH from properly functioning intermittent vent pneumatic controllers due to the practical limitations of metal to metal seals under real world conditions. Accordingly, low level emissions could have been occurring during field measurements in this campaign although the instrument recorded a low or zero value due to instrument resolution limitations.

Therefore, measured emission data points below half the effective resolution of 0.26 SCFH were conservatively assumed to be 0.13 SCFH. Thus, the minimum instantaneous emission rate within any intermittent vent pneumatic controller emission rate time series was assumed to be 0.13 SCFH for all analyses. In addition, an actuation was assumed to have taken place where the instantaneous emission rate exceeded 0.39 SCFH, indicating a clear episodic emission larger than 1.5 times the effective resolution and thus distinguishable from noise (actuation threshold).

Pneumatic Controller Inventory and Classification

A total of 72 sites were selected for the study. Table 1 tabulates the distribution of site type and category by basin.

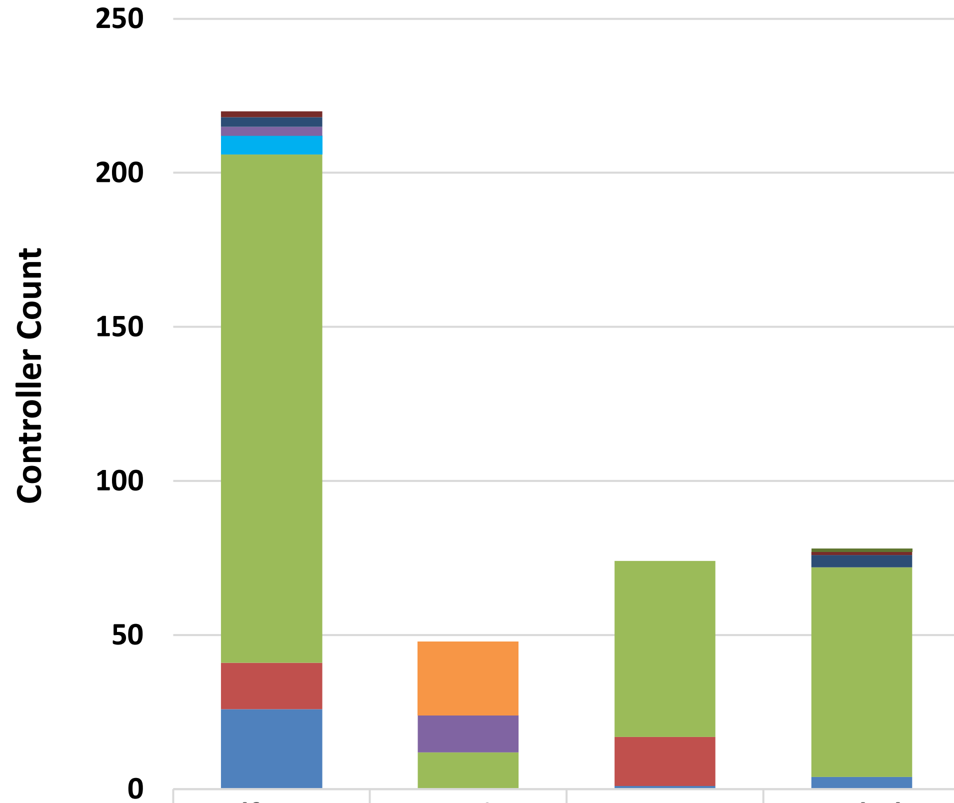
Table 1: Site type and category for the four sampled basins*

Site Type and Category	San Juan	Anadarko	Permian	Gulf Coast	Total
Natural Gas Sites	12	25	0	11	48
Well Site	6	8	0	3	17
Well Production	2	12	0	0	14
Central Production	3	1	0	6	10
Boosting and Gathering	1	4	0	2	7
Oil Sites	0	1	18	5	24
Well Site	0	0	9	2	11
Well Production	0	1	3	3	7
Central Production	0	0	4	0	4
Boosting and Gathering	0	0	2	0	2
Total	12	26	18	16	72

*For a complete description of the site categories see: Table S1 of Pacsi, AP, et al. 2019. Equipment leak detection and quantification at 67 oil and gas sites in the Western United States. Elem Sci Anth, 7: 29. DOI: https://doi.org/10.1525/elementa.368

Controllers at 67 sites were inventoried, including 45 with pneumatic controllers present and 19 sites without non-mechanical controllers. Of the 45 sites with pneumatic controllers present, 40 sites had one or more pneumatic controller powered by natural gas[2], four sites had pneumatic controllers exclusively powered by CO_2 and one site had pneumatic controllers exclusively powered by air. Detailed inventories of the controllers at the 45 sites with pneumatic controllers resulted in the identification of 420 controllers. The set of 420 controllers included 370 powered by natural gas, 39 powered by air or CO_2, seven powered electrically, and four out-of-service or with unknown power source. The natural gas powered pneumatic controllers were further classified into the three EPA categories (US EPA, 2014a): 1) intermittent vent; 2) continuous low bleed (<=6 SCFH) or 3) continuous high bleed (>6 SCFH) pneumatic controllers. Pneumatic controllers lacking sufficient detail to classify between intermittent or continuous service were labeled as "unclassified" (Figure 2).

[2] Natural gas in the context of this study is inclusive of field gas, sales gas, processed gas, and other types of predominantly methane gas. The term excludes gas streams that were predominantly CO_2 or compressed air.



	Gulf Coast	Permian	San Juan	Anadarko
Unknown				1
Not Operating	2			1
Electric	3			4
CO2 Pneumatic		24		
Instrument Air Pneumatic	3	12		
NG Unclassfied	6	0	0	0
NG Intermittent	165	12	57	68
NG Low Bleed	15	0	16	0
NG High Bleed	26	0	1	4

Figure 2: Inventory of pneumatic controller types by basin.

The majority of inventoried natural gas-powered controllers were intermittent vent controllers. as shown in Figure 2. The Permian basin sites in this study generally used either mechanical, instrument air or CO_2 operated pneumatic controllers, resulting in a small number of natural gas-powered pneumatic controllers at those sites.

Pneumatic Controller Emission Measurements

Project time constraints only allowed for emission measurements on a subset of inventoried controllers. Exhaust emissions were measured from 308 natural gas powered pneumatic controllers at 39 sites. The vast majority of measurements were conducted using a GHD recording high-flow type instrument with readings predominantly captured at about two second sample rates over a measurement period of approximately 15 minutes. Controller meta-data was collected for each pneumatic controller measured. The meta-data included manufacturer, model number, type, service and photos. Each controller measured was classified into one of the US EPA's regulatory types: intermittent vent, continuous vent low-bleed bleed, or continuous vent high-bleed. The majority (85%) of the pneumatic controllers measured were intermittent vent type which is broadly consistent with the overall inventory for this study as shown in Figure 3. [3]

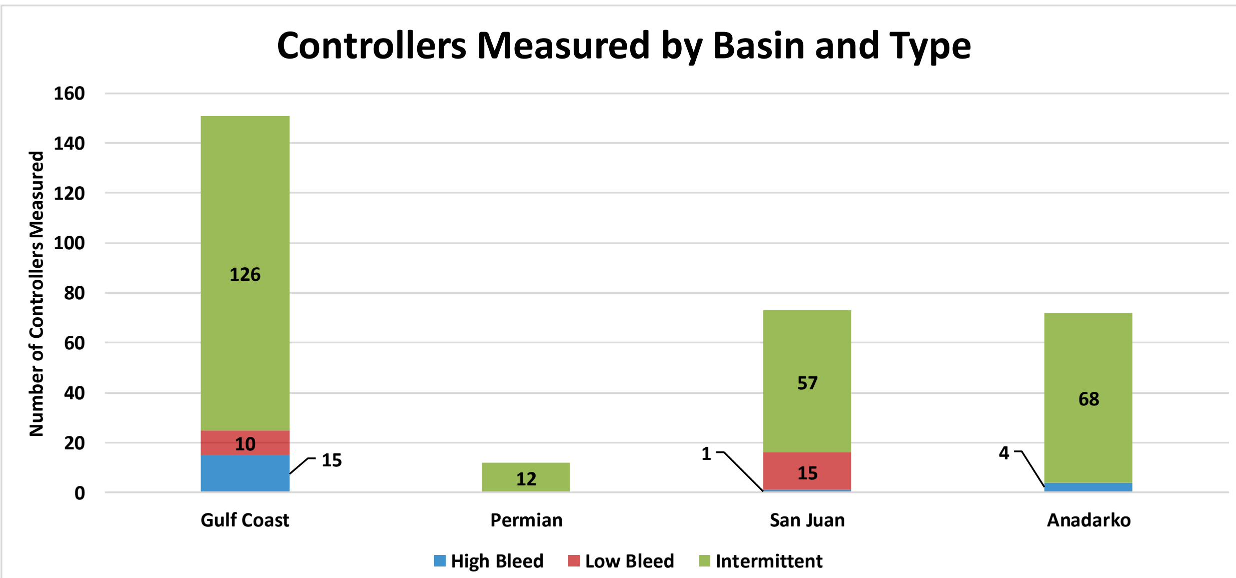


Figure 3: Number of pneumatic controllers measured by EPA type and basin.

Previous studies have reported pneumatic controller emission results on an average emission rate per controller basis. For this study, average emission rates by basin and controller type are shown relative to US EPA Subpart W emission factors (Figure 4, Table 2), however they should be interpreted with caution. Basin-level average emission rates for both continuous vent, high and low bleed types are limited by small sample sizes. Although the sample size of the intermittent vent pneumatic controller measurements is larger, intermittent vent controllers are analyzed by the subcategories of properly functioning and malfunctioning which reduces the sample size in each subcategory.

[3] Three of the controllers measured and classified as intermittent vent controllers are listed as displacement tanks for wastewater/oil by the manufacturer and differ from the typical understanding of intermittent vent controllers. However, they were retained in the study reports and statistics.

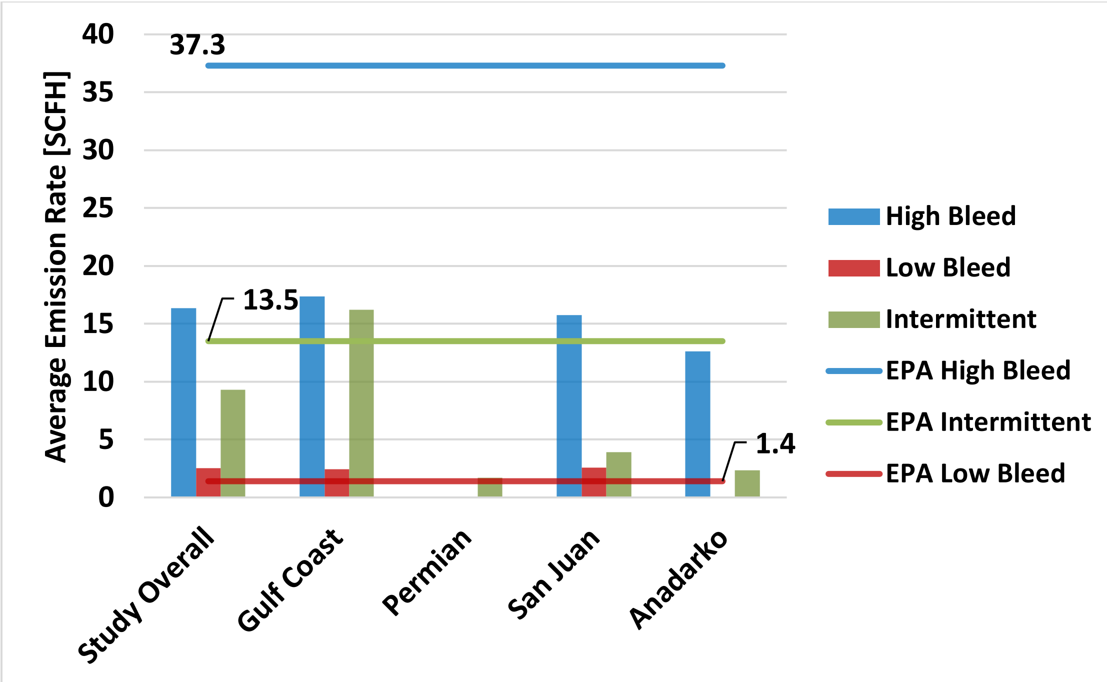


Figure 4: Average emission rates per controller by type and basin compared to US EPA Subpart W emission factors.

Table 2: Average emission rates per controller by type and basin in SCFH.
ND indicates that no measurements were made for the type of controller within the basin.

	Study Overall	Gulf Coast	Permian	San Juan	Anadarko
All Controllers	9.2	15.4	1.7	3.7	2.9
High Bleed	16.4	17.4	ND	15.7	12.6
Low Bleed	2.6	2.7	ND	2.6	ND
Intermittent	9.3	16.2	1.7	3.8	2.3

The intermittent vent pneumatic controller average emission rate for all measured intermittent vent pneumatic controllers represents the average emission rates of properly functioning and malfunctioning controllers. Actions taken to minimize the number of malfunctioning pneumatic controllers, such as a proactive monitoring and repair program, may result in a reduction in the number of malfunctioning intermittent controllers and thus reduce emissions. Emission factors were derived by the properly functioning and malfunctioning sub-categories, akin to leak/no-leak factors applied to fugitive components (US EPA, 1995). For the overall study, malfunctioning intermittent pneumatic controllers (~38% malfunction rate in this data set) contributed about 98% of the observed intermittent pneumatic controller emissions.

Intermittent Vent Pneumatic Controller Emissions Analysis

In this study, 263 intermittent vent pneumatic controllers were measured. The 120 resultant time series with no instantaneous measurements greater than 0.39 SCFH (1.5 times the effective resolution, the assumed actuation threshold) were considered minimally emitting. Emissions with data above the actuation threshold were observed in the remaining 143 time series. Any individual instantaneous measurement in the time series below 0.13 SCFH (1/2 the effective resolution of 0.26 SCFH) was replaced with a value of 0.13 SCFH.

Based on the observed time series, pneumatic controllers were classified as either properly functioning or malfunctioning. Minimally emitting time series were a subset of properly functioning time series where no actuations were observed. Properly functioning intermittent pneumatic controller time series were those characterized by either distinct, episodic actuations, with a clear return to a baseline of 0.13 SCFH in between actuations, or with consistently *de minimis* emission rate (< 0.39 SCFH – actuation threshold of 1.5 times the effective resolution). Time series from malfunctioning intermittent pneumatic controllers typically showed continuous emissions with no return to baseline. Examples of a properly functioning intermittent pneumatic controller (top panel) and a malfunctioning intermittent pneumatic controller (bottom panel) are show in Figure 5.

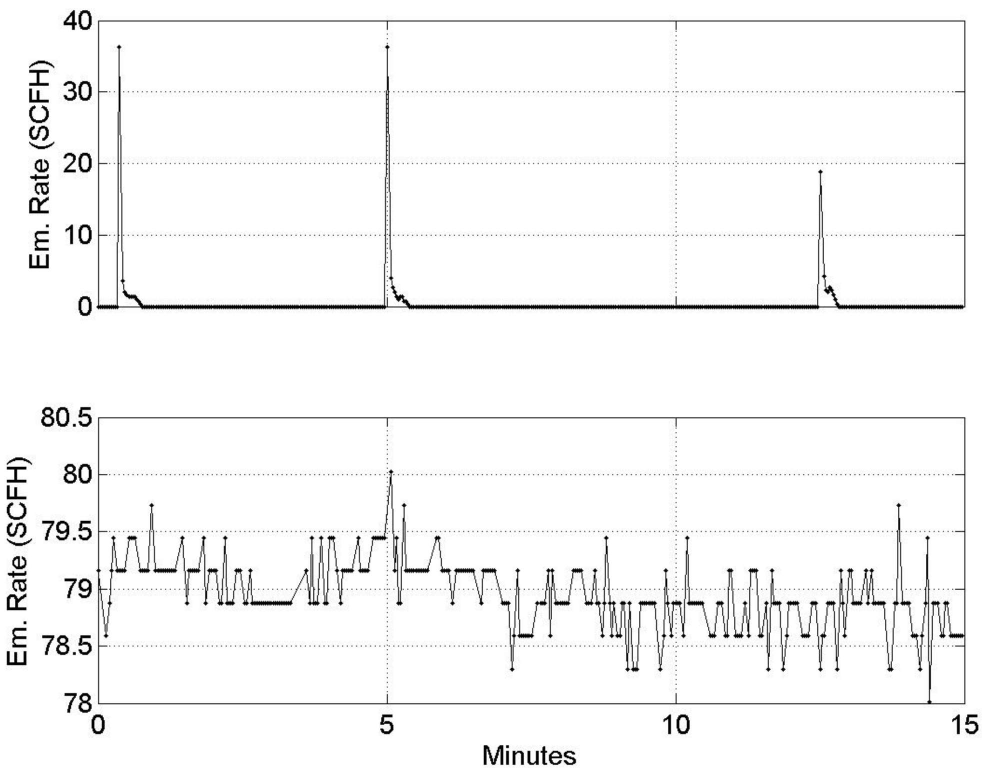


Figure 5: Top panel: Properly functioning intermittent vent pneumatic controller (the baseline level is 0.13 SCFH). Bottom panel: Malfunctioning intermittent vent pneumatic controller.

The following algorithm was developed to provide a consistent basis for classification as described below.

Intermittent vent controllers were classified as properly functioning where:

1. The median emission rate was less than 0.39 SCFH
2. Greater than 25% of a time series had an emission rate less than 0.39 SCFH
3. All individual actuations lasted less than 180 seconds (~20% of the measurement duration)

Otherwise, the pneumatic controller was classified as malfunctioning.

The third criterion above is based on the expectation that actuations should occur over a limited duration with a return to a low level value. The 3 time series that failed this criteria had unexpectedly prolonged actuations indicative of a malfunctioning intermittent controller (*i.e.*, such as the bottom panel in Figure 5). Automated classifications were visually confirmed based upon engineering judgment.

The automated algorithm for determining if an intermittent pneumatic controller is properly functioning or malfunctioning used here is specific to this dataset because it is based on the minimum effective resolution of the dataset. The algorithm can potentially be adapted for use on other datasets based on their minimum effective resolution, but this should be verified prior to its implementation.

Average emission rates for each of the intermittent vent controllers were calculated (Table 3). Of the 263 total time series analyzed, 120 were minimally emitting. Of the 120 minimally emitting intermittent controllers, 11 had an average emission rate greater than 0.13 SCFH but less than 0.39 SCFH with a mean value of 0.21 SCFH, giving an average overall emission rate of 0.137 SCFH for all 120 minimally emitting intermittent pneumatic controllers. An additional 44 were classified as properly functioning with a mean emission rate of 0.66 SCFH for a total of 164 properly functioning intermittent pneumatic controllers with a mean emission rate of 0.28 SCFH. An additional 99 intermittent pneumatic controllers were malfunctioning with a mean emission rate of 24.1 SCFH. The average emissions per controller for all 263 intermittent vent controllers was 9.25 SCFH.

Table 3: Average emission rates per intermittent controller by type in SCFH.

	Average Emission Rate (SCFH)
Properly Functioning	0.28
Malfunctioning	24.1
All Intermittent	9.25

Actuation Frequency Sensitivity Analysis

Pneumatic controllers that were observed as minimally emitting during the study were expected to actuate on some frequency despite not having been observed over the course of this study. A sensitivity case was evaluated to assess the maximum potential error in the average emission rate based upon a conservative scenario assuming the measurement team had just missed an actuation. The sensitivity case assumed each of the minimally emitting pneumatic controllers actuated every 20-minutes with an actuation volume equal to the average emission volume per actuation of the properly functioning, but not minimally emitting, pneumatic controllers (0.02 SCF per actuation). The average emissions per controller for all 263 intermittent pneumatic controllers increased by ~0.1 % from 9.25 SCFH to 9.26 SCFH under this scenario. Thus, unaccounted for actuations of properly functioning controllers, even at a very high actuation rate, had a minimal effect on the total emissions which is consistent with sensitivity analyses in Allen et al. (2015).

Intermittent Pneumatic Controller Population Distributions

Cumulative distribution functions (CDFs) were fitted to the data to facilitate visualization of the relative populations (properly functioning vs. malfunctioning across regions). Weibull CDFs were fitted to the average emission rate data. Figure 6 shows the CDFs fitted to emission rates for the malfunctioning and properly functioning intermittent pneumatic controllers, respectively. Minimally emitting controllers were omitted from the fitting procedure because fitting a continuous distribution to data that contains a large number of non-unique data points leads to poor distribution fits. Those data were added back into the probability distribution plots (Figures 7 and 8).

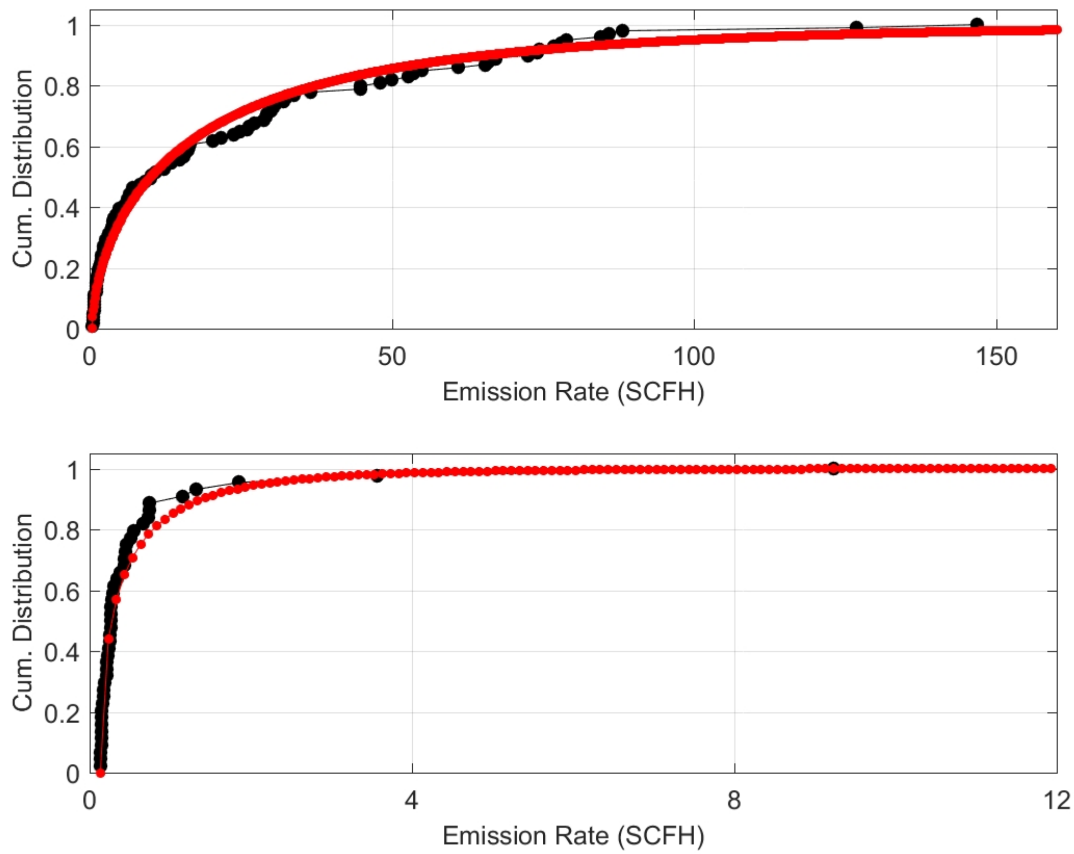


Figure 6: Top panel: Malfunctioning intermittent pneumatic controller emission rates (black circles) with fitted CDF (red line). Bottom panel: Properly functioning intermittent pneumatic controller emission rates (black circles) with fitted CDF (red line) excluding minimally emitting data.

Table 4: Parameters of the Weibull CDF distributions fitted to the malfunctioning and properly functioning data (excluding minimally emitting).

	Weibull scale parameter	Weibull shape parameter
Properly functioning	0.2735	0.5463
Malfunctioning	17.4266	0.6294

The relative contribution of emissions as a function of emission rate for properly functioning and malfunctioning intermittent vent pneumatic controllers, including minimally emitting pneumatic controllers, is shown in Figure 7. The malfunctioning intermittent controllers account for about 98% of the measured emissions from intermittent vent controllers. The primary driver of emissions in this dataset are the highest emissions from malfunctioning intermittent vent pneumatic controllers. The top 15 pneumatic controller emission rates (15 of the 263 or ~5.7 %), which were malfunctioning and emitting at a rate of at least 60 SCFH, account for about 51% of the emissions from all 263 intermittent pneumatic controllers.

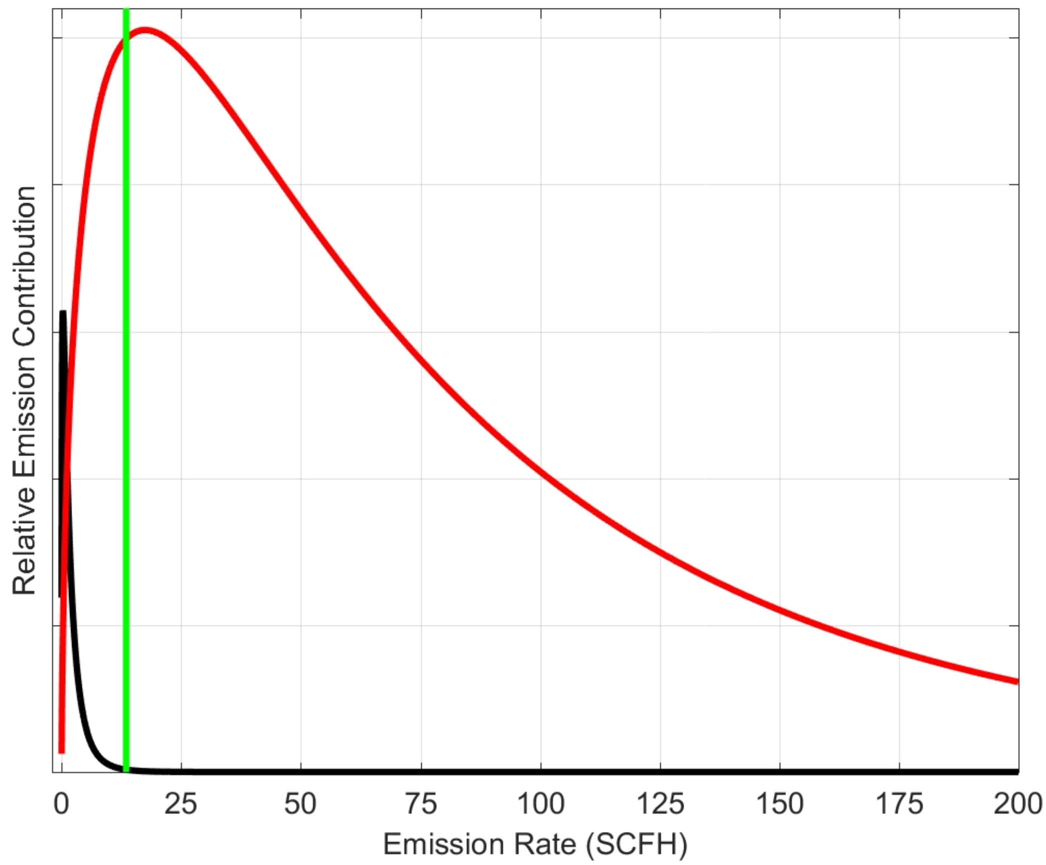
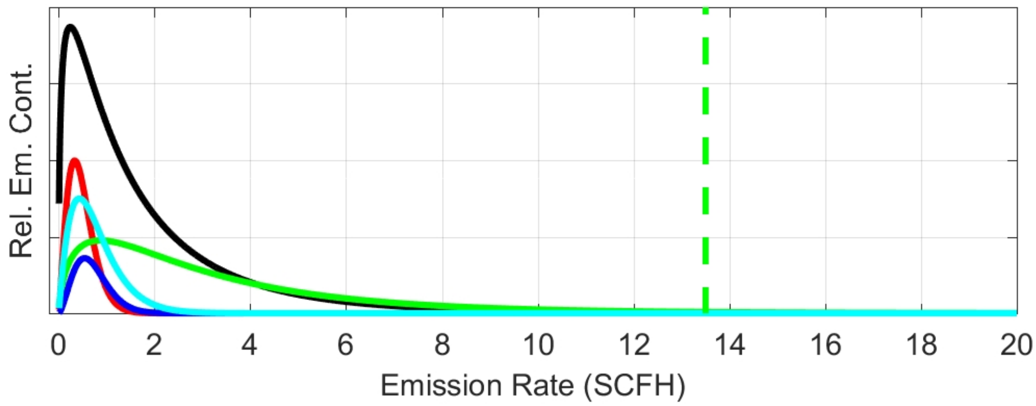


Figure 7: Relative contribution of properly functioning intermittent pneumatic controllers including minimal emitting controllers (black line), malfunctioning intermittent pneumatic controllers (red line), and the Subpart W intermittent vent pneumatic controller emission factor (green line).

A similar analysis was performed on the subsets of data for each of the four basins included in this study. The relative contributions of emissions for each region as a function of emission rate for properly functioning and malfunctioning pneumatic controllers, including minimally emitting pneumatic controllers, are shown in Figure 8, while Table 5 provides the Weibull scale and shape parameters for the fits. Note that there was only one malfunctioning pneumatic controller in the Permian basin so a fit was not possible.



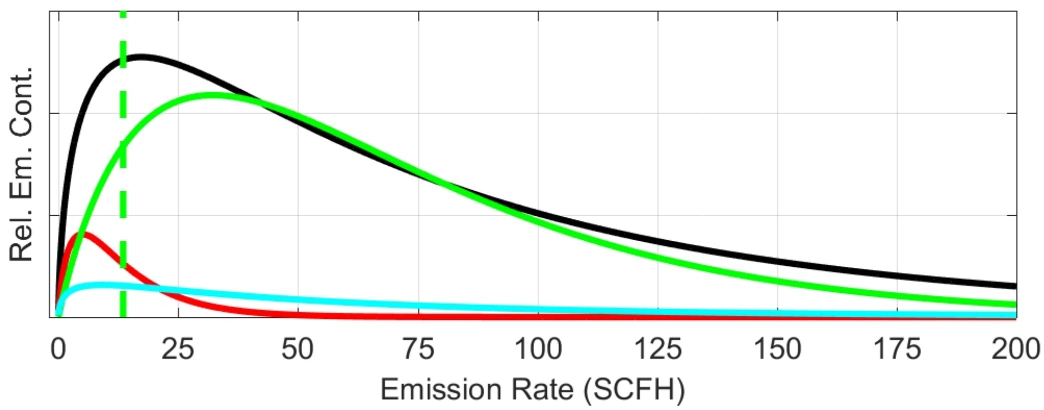


Figure 8: Top panel: Relative contribution of emissions for properly functioning intermittent pneumatic controllers, including minimally emitting controllers, by basin. Bottom panel: Relative contribution of emissions for malfunctioning intermittent pneumatic controllers by basin.

For both panels: The black line represents all the data (Figure 8). The red line represents the Anadarko basin, the green line represents the Gulf Coast basin, the blue line represents the San Juan basin. The green dashed line represents the Subpart W intermittent vent pneumatic controller emission factor.

Table 5: Weibull distribution parameters for properly and malfunctioning pneumatic controllers for the four basins.

Basin	Weibull scale parameter	Weibull shape parameter
Properly Functioning		
Anadarko	0.3377	1.3425
Gulf Coast	0.8784	0.7180
Permian	0.5451	1.5642
San Juan	0.4349	1.0913
Malfunctioning		
Anadarko	5.0269	0.8210
Gulf Coast	32.9045	0.9568
Permian	---	---
San Juan	9.1526	0.5492

Emission Factor Development

The Gulf Coast basin contributed the largest number of emitters and volume of emissions to the malfunctioning intermittent controller category as well as total emissions in this study. The Gulf Coast basin had 13 of the 14 top emitting intermittent pneumatic controllers. The remaining top emitting malfunctioning intermittent pneumatic was located in the San Juan basin. Excluding the single top emitter for the San Juan basin drops the mean emission rate value per malfunctioning intermittent controller for the San Juan basin from 17.4 SCFH to 7.5 SCFH and also significantly alters the Weibull scale parameter in the CDF fit for malfunctioning intermittent pneumatic controllers in the San Juan basin from 9.1526 to 5.6217. This illustrates the sensitivity of the pneumatic controller emission rate to the distribution of properly functioning and malfunctioning intermittent pneumatic controllers.

The skewed distribution of emissions, where a small number of malfunctioning intermittent pneumatic controllers accounted for the majority of measured emissions, suggests that a malfunctioning pneumatic controller monitoring and repair program may be effective in reducing emissions far below the current emissions estimates. Many operators report that they voluntarily practice such an inspection program in locations where the company is already performing leak detection and repair inspections. Unfortunately, there is no opportunity to demonstrate the reductions that such a program achieves because Subpart W requires the application of a single factor in the tabulation of intermittent vent pneumatic controller emissions irrespective of whether the controller is functioning properly or malfunctioning.

Table 6 shows the detectable portion of this study's measured emissions under different detection threshold scenarios. Malfunctioning intermittent vent pneumatic controllers emitting at a rate > 2 SCFH (an emission rate likely detectable with an optical gas imaging camera) account for about 97.6 % of the total emissions based upon the intermittent vent pneumatic controllers measured in this study. For a threshold of 10 SCFH, which may be detectible by audio-visual-olfactory (AVO) monitoring, about 92.3% of the emissions could potentially be located and significantly reduced.

Table 6: Specified detection threshold, the number and percentage of malfunctioning intermittent pneumatic controllers emitting above that threshold, as well as the percentage of total intermittent vent controller emissions represented by malfunctioning controllers emitting above the specified threshold.

Detection Threshold (SCFH)	# of Intermittent pneumatic controllers	% of Intermittent pneumatic controllers	Detectable % of Total Intermittent Controller Emissions
2	78	29.6	97.65
4	66	24.6	96.04
6	61	22.7	95.05
10	51	19.3	92.30
25	35	13.3	81.78
50	19	7.2	59.97
75	8	3.0	31.51
100	2	0.8	11.25

A stratified emission factor approach (e.g. Table 3) could be applied to intermittent pneumatic controllers to account for properly functioning and malfunctioning controllers. The approach is analogous in design to application of leaker emission factors for equipment leaks in Subpart W when an OGI leak inspection program is in place. Such an approach would enable demonstration of reductions by operators who are voluntarily conducting pneumatic controller inspections and potentially incentivize further voluntary inspections to identify malfunctioning pneumatic controllers.

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ANNEX B: API Comments on Proposed Subpart W, Submitted July 21, 2023

July 21, 2023

<u>Submitted electronically to docket No. EPA-HQ-OAR-2019-0424</u>

Jennifer Bohman
Climate Change Division, Office of Atmospheric Programs (MC-6207A)
Environmental Protection Agency
1200 Pennsylvania Ave. NW
Washington, DC 20460

Re: Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule; Docket No. EPA-HQ-OAR-2019-0424

Dear Ms. Bohman:

The American Petroleum Institute, the American Exploration & Production Council, Independent Petroleum Association of America, The Petroleum Alliance of Oklahoma, and the Offshore Operators Committee (collectively "Industry Trades") appreciate the opportunity to offer comments to the U.S. Environmental Protection Agency (EPA) on the proposed "Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule" (proposed on May 22, 2023). With this submittal, the Industry Trades seek to continue our participation in the rulemaking process as a collaborative stakeholder by providing meaningful solutions to address EPA's goals while addressing the burden of data collection (and identifying potential unintended consequences) that could result if the rulemaking is finalized as proposed.

We have participated as key collaborative stakeholders throughout the process of developing the EPA Greenhouse Gas Reporting Program (GHGRP) by contributing expertise and proposing solutions that address EPA's policy goals while reflecting the reality of the industry and its evolving day-to-day operating practices. The Industry Trades have directed our efforts toward seeking a balance between the burden of data collection and reporting, the need to protect sensitive information and ensure that reporting requirements are placed on the correct reporters, and the need for providing the highest quality data that will help inform decision makers and the public.

These comments reflect our continued interest in the evolution of the GHGRP to provide an accurate accounting of greenhouse gas (GHG) emissions from facilities across the full value chain of the oil and natural gas industry. Our comments cover concerns and recommendations in the wide range of sectors that relate to the operations of our collective members.

INDUSTRY TRADES' INTERESTS

The American Petroleum Institute (API) is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. GDP. API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators and marine transporters as well as service and supply companies providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader convening subject matter experts from across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 800 standards to enhance operational safety, environmental protection, and sustainability in the industry.

Additionally, API has a history of working with EPA to refine and improve data collection, emission estimation and emission reporting under various subparts of the GHGRP. API has worked with both EPA and the regulated industry for more than two decades in developing methodologies for estimating greenhouse gas emissions from oil and natural gas operations. API's first *Compendium of GHG Emissions Methodologies for the Oil and Natural Gas Industry* (the *Compendium*) was published in 2001. As reflected in EPA's efforts to revise the GHGRP and API's recent publication of a 4th edition of the *Compendium (November 2021)*, our abilities to estimate and measure greenhouse gas emissions are continually evolving.

The American Exploration & Production Council (AXPC) is a national trade association representing 30 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. It is important that regulatory policy enables us to support continued progress on both fronts through innovation and collaboration.

The Independent Petroleum Association of America (IPAA) represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 91 percent of oil and natural gas wells in the U.S., producing 83 percent of oil and 90 percent of natural gas in the U.S.

The Petroleum Alliance of Oklahoma (The Alliance) represents more than 1,400 individuals and member companies and their tens of thousands of employees in the upstream, midstream, and downstream sectors and ventures ranging from small, family-owned businesses to large, publicly traded corporations. The Alliance's members produce, transport, process and refine the bulk of Oklahoma's crude oil and natural gas and play an essential role in providing products and solutions to improve human health and welfare, power the global economy, and make modern life possible. Abundant, clean-burning natural gas has enabled the United States to become the global leader in greenhouse gas emissions reductions. The Alliance's members have and will continue to deploy technologies that result in meaningful greenhouse gas emission reductions through innovative solutions and breakthrough technologies while meeting the energy demands of today and the future.

The Offshore Operators Committee (OOC) is an offshore energy trade association that serves as a technical advocate for over 90% of the companies operating on the U.S. Outer-Continental Shelf (OCS). Founded in 1948, the OOC has evolved into the principal technical representative regarding regulation of offshore energy operations. Our members include operators and service providers working to ensure safe production of offshore energy for the workforce and the environment.

Industry Trades' Comments on EPA's "Revisions and Confidentiality Determinations for Data Elements under the Greenhouse Gas Reporting Rule"

Docket ID No. *EPA-HQ-OAR-2019-0424*

1. Introduction

The Industry Trades support efforts to improve accuracy and enhance consistency between regulatory programs as it relates to greenhouse gas (GHG) reporting. The comments provided herein reflect feedback from the Industry Trades on the proposed changes to the GHGRP for subparts impacting the oil and natural gas industry, with a particular focus on the newly proposed Subpart B's burdensome reporting and recordkeeping requirements as well as potential unintended consequences resulting from these requirements. The Industry Trades are respectfully submitting comments on the following subparts:

- Subpart A – General Provisions
- Subpart B – Energy Consumption
- Subpart C – General Stationary Fuel Combustion
- Subpart P – Hydrogen Production
- Subpart Y – Petroleum Refineries
- Subpart PP – Suppliers of Carbon Dioxide
- Subpart UU – Injection of Carbon Dioxide
- Subpart WW – Coke Calciners

As presented in Sections 2 and 3 below, the Industry Trades' comments are organized by proposed amendments to current subparts and proposed new subparts, respectively.

2. Comments on Proposed Amendments to 40 CFR Part 98

1. Subpart A – General Provisions

a. The Industry Trades support EPA's proposal to update the Global Warming Potentials (GWPs) for calculating CO_2-equivalent (CO2e) emissions of non-CO_2 gases (CH_4, N_2O, HFCs, PFCs, SF_6, and NF_3) to reflect updated estimates contained in the Intergovernmental Panel on Climate Change's (IPCC's) Fifth Assessment Report (AR5), based on a 100-year time horizon. We agree with EPA's proposal to use the 100-year GWP for methane. The proposed GWP changes to Table A-1 in Subpart A are aligned with the Inventory of U.S. Greenhouse Gas Emissions and Sinks [i.e., the U.S. EPA GHG Inventory (GHGI)] and complies with the United Nations Framework Convention on Climate Change (UNFCCC) decision to use GWP values from the IPCC AR5 in national reporting by countries by the end of 2024.

   While the Industry Trades agree with the proposed revisions to the GWPs included in Subpart A, the Industry Trades request that EPA clarify in the preamble to this proposed rulemaking the impacts on the reported total CO_2e emissions due to changing the GWP (particularly for methane), without any actual change in mass emissions. With an increased focus on methane emissions from the oil and natural gas industry, it is important to inform stakeholders that future increases in CO_2e emissions due to the change in GWP are not reflective of any actual mass emission increases. Likewise, the Industry Trades recommend that the EPA acknowledge that combustion CO_2e emissions will be impacted from both the reduction in N_2O GWP, as well as the increase in CH_4 GWP.

2. Subpart C – General Stationary Fuel Combustion

The EPA's proposed revisions include requirements to report emissions from the stationary combustion category that result from an electricity generating unit (EGU) and to report an estimated fraction of total emissions from a multi-unit group of combustion sources under 40 CFR 98.36(c) attributable to EGUs. The preamble to the supplemental proposed rule states that "some manufacturing facilities, such as petroleum refineries and pulp and paper manufacturers, operate stationary combustion sources that generate electricity. Reporting of an EGU indicator for these units would allow the EPA to assign the emissions from any electricity generating units at the facility more appropriately to the power plant sector."[1]

a. An EGU is not specifically defined within Subpart A or Subpart C; the definition of an "electricity generation source category" EGU found in Subpart D in 98.40 includes only EGUs that are subject to monitoring and reporting requirements found in 40 CFR Part 75. While EGUs are not defined in Subpart A explicitly, a footnote to Table A-7, "Data Elements that Are Inputs to Emission Equations and for Which the Reporting Deadline is March 31, 2015" states that for sources reporting under Subpart C (cited below with **emphasis added**). The Industry Trades are seeking clarification on the definition of an EGU for this reporting element; as proposed, it is unclear what units would meet this reporting requirement. The Industry Trades support a definition that aligns with the footnote presented under Table A-7:

   Required to be reported only by: (1) Stationary fuel combustion sources (e.g., individual units, aggregations of units, common pipes, or common stacks) subject to subpart C of this part that contain at least one combustion unit ***connected to a fuel-fired electric generator owned or operated by an entity that is subject to regulation of customer billing rates by the PUC (excluding generators connected to combustion units subject to 40 CFR part 98, subpart D) and that are located at a facility for which the sum of the nameplate capacities for all such electric generators is greater than or equal to 1 megawatt electric output;*** *and (2) stationary fuel combustion sources (e.g., individual units, aggregations of units, common pipes, or common stacks) subject to subpart C of this part that do not meet the criteria in (1) of this footnote that elect to report these data elements, as provided in § 98.36(a), for reporting year 2014.*

   Additionally, the Industry Trades propose that the definition of an EGU specifically exclude drivers used to power equipment including but not limited to compressors and pumps.

b. The Industry Trades also propose that the EPA provide clarification and flexibility to 98.34(e), which references 98.34(d) to determine the biogenic portion of CO_2 emissions. Since gaseous fuels can be sampled prior to combustion for biogenic content and used to determine the biogenic portion of CO_2 emissions, the Industry Trades propose the following additional language (***in red***) to provide options to use other approved sampling standards or industry standard practices:

   "(e) For other units that combust combinations of biomass fuel(s) (or heterogeneous fuels that have a biomass component, *e.g.,* tires) and fossil (or other non-biogenic) fuel(s), in any proportions, ASTM D6866-16 and ASTM D7459-08 (both incorporated by reference, see §98.7) may be used to determine the biogenic portion of the CO_2 emissions in every calendar quarter in which biomass and non-biogenic fuels are co-fired in the unit. Follow the procedures in paragraph (d) of this section. ***As an alternative to ASTM D7459-08 and paragraph (d), an entity may also use a method published by a consensus-based standards organization, if such a method exists, or you***

[1] 88 Fed. Reg. at 32873.

may use industry standard practice. The method(s) used shall be documented in the GHG Monitoring Plan required under 98.3(g)(5). If the primary fuel for multiple units at the facility consists of tires, and the units are fed from a common fuel source, testing at only one of the units is sufficient."

c. In the proposed revisions to Subpart C, EPA should move all combustion calculations and reporting requirements from Subpart W to Subpart C in order to avoid confusion in reporting natural gas combustion emissions, as previously articulated in the Industry Trades' comments submitted on October 6, 2022.[2]

d. Additionally, site-specific CH_4 emission factors may be available for certain equipment from the equipment manufacturer or from acceptable testing methodologies. EPA should allow for the use of site-specific CH_4 emission factors as an alternative to the CH_4 emission factors in Tables C-2 or Table W-9, with the following proposed addition (below, ***in red***) to 98.33(c)(1) through 98.33(c)(4). Required use of generic factors disincentivizes reporters to mitigate and reduce methane emissions. This change would also be consistent with the recently proposed updates to 40 CFR Part 98, Subpart W.

   *EF = Fuel-specific default emission factor for CH_4 or N_2O, from Table C–2 of this subpart (kg CH_4 or N_2O per mmBtu), except for natural gas compressor drivers at facilities subject to subpart W of this part, which must use the applicable CH4 emission factor from Table W–9 to subpart W of this part, **Table C-2, or site-specific emission factors**.*

3. Subpart P – Hydrogen Production

In general, this subpart proposes to include all facilities that produce a hydrogen product(s) including non-merchant hydrogen production process units previously reported under Subpart Y (Petroleum Refineries) and captive plants, but excludes reporting of catalytic reforming units. EPA also proposes that the associated steam consumption for these units and their fuel usage previously reported under Subpart C (Combustion) be reported under Subpart P.

a. The Industry Trades support the exemption to the source category in 40 CFR 98.160(b)(1)(B) clearly excluding catalytic reforming units covered under Subpart Y from reporting in Subpart P.

b. The Industry Trades do not support amending the source category requiring reporters to report combustion from hydrogen production process units under Subpart P in lieu of Subpart C as proposed in 40 CFR 98.160(c). These units may not be metered separately from other combustion units located at an integrated facility such as a refinery with a hydrogen production unit; therefore, we recommend reporting stationary combustion emissions from hydrogen production under Subpart C. If those emissions have to be reported under Subpart P instead of Subpart C, EPA shall allow engineering estimation for fuel consumption to avoid burdensome retrofitting of fuel meters.

c. The Industry Trades are also concerned that reporting the net quantity of steam consumed as proposed under 40 CFR 98.166(b)(9) could result in duplicative reporting based on what is proposed to be reported under Subpart B (i.e., where steam is provided by a third-party supplier). The Industry Trades respectfully request removal of this requirement from Subpart P.

d. EPA is seeking comment as to how to determine when or how a source will trigger or cease to report under Subpart P. EPA is proposing to use hydrogen production rates as the trigger for GHG reporting, instead of direct GHG emissions. EPA believes this approach will capture hydrogen production units which use energy (rather than

[2] API comments to EPA's proposed GHGRP Rule, October 6, 2022.

fossil fuel combustion). The Industry Trades believe that these types of units will frequently be part of a larger operation already subject to GHG reporting, and energy consumption will be captured under Subpart B.

The Industry Trades offer the following recommendations on the provisions to cease reporting:

i) Hydrogen production process units which produce hydrogen but emit no direct GHG emissions should become eligible to cease reporting starting January 1 of the following year after the cessation of direct GHG emitting activities associated with the process;

ii) If the direct GHG emissions remain below 15,000 MT CO2e or between 15,000 and 25,000 MT CO2e, the Industry Trades recommend that reporting would be required for 3 or 5 years respectively, aligned with the existing Part 98 reporting off-ramp provisions; or

iii) If EPA establishes a hydrogen production threshold for reporting, then the Industry Trades recommend that falling below that production threshold should be the trigger for cessation of reporting, either starting January 1 of the following year or on a parallel structure to the 3- and 5-year off-ramp emission thresholds.

The Industry Trades recommend that if the hydrogen production unit continues to combust fuel or is part of a larger process with multiple (or comingled) combustion units, those emissions will continue to be reported under Subpart C, consistent with the Industry Trades' recommendation above. Similarly, if the process unit is part of a refinery, any non-combustion energy consumption related to the process unit will be captured under proposed Subpart B.

e. EPA is seeking input on requiring sales information for hydrogen production. There are several reasons the Industry Trades believe this should not be required unless proposed through a separate rulemaking process.

i. First, it is important to note that the hydrogen market is in its very early stages, and it is unknown how hydrogen for energy consumption may evolve in the near or longer term. Codifying this in the regulation will require a full regulatory rulemaking process to address changing market conditions. As this market is evolving, it is possible this proposed new GHGRP requirement will become overly burdensome without providing useful information.

ii. Second, this information is considered "Confidential Business Information" (CBI) by both the seller and/or the buyer and may be restricted by confidentiality provisions in sales contracts; therefore, it should not be publicly reported.

iii. Finally, it is not clear how this information would be used by EPA; information necessary to determine emissions intensity is already provided in Subpart P.

If EPA disagrees with the recommendations above, the Industry Trades recommend limiting the reporting requirement to include only bulk hydrogen sales quantities, without specifying individual buyers identities and sales quantities. If reporting sales information is required, the Industry Trades recommend reporting at corporate level, rather than individual transactions, and that a cut-off threshold for reporting be established, similar to Subpart NN.

4. Subpart Y – Petroleum Refineries

Proposed revisions to Subpart Y include deletion of the reference to non-merchant hydrogen production plants and to coke calcining units as these are being addressed in Subparts P and WW, respectively. Additionally, EPA is proposing to include a requirement to report the capacity of each asphalt blowing unit.

The Industry Trades support the removal of reporting requirements for non-merchant hydrogen production plants in Subpart Y, and instead report these units under Subpart P. Likewise, the Industry Trades support the reporting of coke calcining units in the newly added Subpart WW.

EPA's rationale for requesting the capacity of each asphalt blowing unit is not clear to the Industry Trades, nor is it clear how this data would be used. t is unclear how the individual capacity data will support more accurate reporting. With the additional data collection and reporting requirements, the Industry Trades would like to better understand EPA's reasoning for requesting this information, so that we can recommend the most appropriate and effective data to meet EPA's objectives.

5. Subpart PP – Suppliers of Carbon Dioxide

As proposed, reporters would be required to report the facility identification number associated with the annual GHG reports for each Subpart RR and VV facility to which CO_2 is provided. Additionally, EPA is seeking comment on whether to expand the reporting requirements for all receivers of CO_2, not just those facilities subject to Subparts RR and VV.

a. The Industry Trades support EPA's efforts to increase accuracy in tracking supplies of CO_2 in the economy, but request EPA to analyze whether both senders and receivers of CO_2 reporting is redundant.

b. The Industry Trades also recommend that EPA provides additional information on how CO_2 suppliers for export could appropriately address exports in their report. For example, clarity in reporting is needed to address situations in which a company supplies CO_2 to a non-reporter that is a subsidiary of a larger company that does report.

c. EPA is seeking comment on further expanding the list of end-use applications reported in 40 CFR 98.426(f) to better account for and track emerging CO_2 end uses. Similar to our comments under Subpart P, the market for CO_2 utilization continues to develop. As such, the Industry Trades are recommending EPA allow, in this rulemaking, flexibility in how this information is reported by allowing reporters the ability to select from a representative range of end-uses, including allowing for instances when the end-use is 'other'. The Industry Trades believe that this information could be captured in EPA's forms and updated as needed to account for innovation in this emerging market.

6. Subpart UU – Injection of Carbon Dioxide

The Industry Trades support EPA's efforts to increase clarity and reduce the potential for double counting of reported emissions. In addition, the Industry Trades support EPA's proposal to revise the proposed text in 40 CFR 98.470(c) from "are not required to report" to "shall not report."

3. Comments on Proposed New Source Categories to Part 98

1. Subpart B – Energy Consumption

This newly proposed subpart will require those reporters that are already subject to reporting under existing provisions in 40 CFR Part 98 to:

- Report the quantity of purchased electricity and thermal energy products;
- Develop a Metered Energy Monitoring Plan (MEMP), which includes identifiers for each meter (including photographs), accuracy specifications, manufacturer's certifications, and other details;
- Keep documentation of quality assurance for purchased electricity monitoring including documentation that meters are conforming with appropriate ANSI standards;
- Keep documentation of quality assurance for purchased thermal energy including copies of the most recent audit of the accuracy of each meter in the purchasing agreement, and if the audit is more than 5 years old, documentation of a request for a new audit to the energy provider (and auditing the meter every 5 years); and
- Report multiple pieces of information for every bill for every purchased energy product meter, as well as requiring submittal of representative billing statements for each purchasing agreement.

The Industry Trades believe many of the provisions within the proposed regulation are extremely burdensome for geographically disparate operations such as those found in the oil and natural gas industry and focus our comments on the unique challenges associated with the meter-level recordkeeping and segment level reporting. In general, the Industry Trades believe there are ways to provide energy consumption information to EPA in a way that achieves EPA's policy goal while not imposing overly burdensome requirements to energy purchasers. Specifically, the Industry Trades recommend EPA to:

- Allow energy purchasers subject to reporting under Subpart W to report energy consumption for all Subpart W activities within a single AAPG hydrocarbon basin;
- Generally, remove meter-level recordkeeping and reporting requirements for the purchaser of energy. If required, any such meter-level requirements should be provided by the electricity supplier as the owner/operator of the meters;
- Remove meter-level QA/QC requirements from the energy purchaser, and instead require energy providers to ensure meters meet required accuracy requirements as the owners of the equipment;
- Exempt Subpart B reports from the "Substantive Error" provisions found in Subpart A; and
- Remove the requirement for a separate MEMP plan, but instead allow reporters to augment existing GHG recordkeeping procedures in the Greenhouse Gas Monitoring Plan (as required in 40 CFR 98.3(g)(5), with additional requirements in subsequent subparts), to include backup documentation, procedures, QA/QC methodologies and other supporting data. This information would be available upon request by EPA.

The following commentary is provided as context to these recommendations.

The proposed recordkeeping, QA/QC and reporting requirements as proposed in this supplemental rulemaking are extremely burdensome for oil and natural gas operations and could result in disincentivizing site electrification. For the oil and natural gas operations that cover a large geographical area consisting of numerous assets, such as onshore oil and gas production and onshore gathering and boosting where the facility encompasses assets across an entire American Association of Petroleum Geologists (AAPG) basin, the number of energy providers and the number of individual meters can be quite significant. For example, in the Permian Basin, a medium-sized upstream operator could have more than 5,000 individual well sites and tank batteries across more than 70,000 square miles and could have hundreds if not thousands of energy meters. Some operations in Alaska and North Dakota have very limited timeframes during which weather would allow for the proposed meter-specific data collection efforts (e.g., meter photos, meter numbers, etc.). Providing documentation on a meter-by-meter basis, including billing statements, would result in an extremely burdensome reporting process, requiring uploading billing statements for hundreds, if not thousands, of meters for individual reporting entities. This is an excessive reporting requirement given that it is likely that the vast majority of meters used in the upstream oil and natural gas segment are for very small energy consuming sites, are not owned or operated by the energy purchaser, and do not serve a specific purpose beyond the reported values. Additionally, imposing these extremely burdensome recordkeeping, reporting and QA/QC requirements for energy purchasers could ultimately result in disincentivizing site electrification, which would be in contrast to the current Administration's drive toward electrification.

Separating energy consumption between reporting segments (e.g., onshore production versus gathering and boosting or gas processing) will be particularly challenging for large integrated operations. The Industry Trades recommend allowing operators subject to Subpart W reporting to report all energy consumption for all reportable Subpart W operations within a single AAPG hydrocarbon basin. Many oil and natural gas operators in the U.S. report both onshore production and gathering and boosting within the same basin and across multiple basins. The proposed data requirements under Subpart B would represent a significant and burdensome data collection effort to not only collect the meter-level data for these multi-asset facilities, but to also then separate the data between the onshore production, gathering/boosting and other GHG reporting segments. In many instances, it is not as simple as a single meter serving a single facility or reporting segment - there are meters recording data across the entire value chain with overlap between the segments - this further complicates a reporters' ability to divide that energy consumption between reporting segments. The Industry Trades request that EPA allow operators who are subject to reporting under Subpart W to report ALL consolidated energy consumption from Subpart W operations within the AAPG basin. If required to report energy by Subpart W source category (i.e., by segment), the Industry Trades request EPA to allow estimation of energy usage between Subpart W facilities, to account for the need to allocate between different facility types (e.g., onshore production, gathering and boosting, etc.) where meters cover energy use across the value chain.

Meter level identification, auditing, accuracy and QA/QC requirements should not be incumbent upon the energy purchaser; instead, these requirements should apply to the meter owner, which is the energy provider. The Industry Trades are concerned that the monitoring and QA/QC requirements proposed in 40 CFR § 98.24, and the reporting requirements in 40 CFR §98.26, will be particularly burdensome given that many of the proposed accuracy and QA/QC requirements would be the responsibility of the energy purchaser rather than the energy provider, despite the fact the energy purchaser does not own, maintain or control the meters. Placing the responsibility for the proposed data requirements on the energy purchaser is inappropriate because it is the energy providers (such as electric utilities) that own and operate the energy meters and are responsible for their accuracy. Further, it is not uncommon for energy providers to change or replace meters without informing the electricity purchaser; therefore, reporting any meter-specific data supplied by an energy purchaser could become inaccurate without the knowledge of the purchaser. Similarly, the energy purchaser does not have access to documentation that the meters conform to ANSI standards, and likely does not have the ability to request that information from the energy provider.

As proposed, the recordkeeping and reporting requirements in Subpart B require reporting detailed supplemental data not required by any other subpart in the GHGRP, and therefore should not be required here. Reporters are not required to submit this level of documentation for other subparts, but instead follow the recordkeeping requirements codified in 40 CFR and the appropriate subparts. The Industry Trades support that same approach for Subpart B. If EPA requires meter-level reporting, the Industry Trades suggest the requirement for supplying energy meter data should reside with the energy provider, not the purchaser.

The Industry Trades provide additional comments on the following specific aspects of the supplemental proposed rule.

Meter-Level Accuracy Assurance Requirements Should Not Fall Upon the Energy Purchaser

As described above, the Industry Trades believe energy purchasers should not be held responsible for accuracy attestations on behalf of energy providers. If an electricity purchaser does not purchase, maintain or monitor meters used for billing purposes, the burden of demonstrating that the meters meet the accuracy requirements of 40 CFR§ 98.24(b) should not fall upon the electricity purchaser; rather, the electricity provider should be responsible for this demonstration. The Industry Trades respectfully recommend removing the proposed requirements in 40 CFR § 98.24(a)(5) and (b) and requiring energy providers to report these certifications.

Alternatively, the Industry Trades recommend that the certification requirements found in 40 CFR §98.24(a)(5) and (b) should be provided by each electricity provider for all meters in the service area, rather than a certification on a meter-by-meter basis.

Meter-Level Recordkeeping and Reporting Requirements

As proposed, 40 CFR § 98.24(a)(2) requires reporters to collect a meter identifier and a photograph of each meter included in the MEMP. Collecting this information from hundreds or thousands of remote well pads, pipelines, and compressor stations, many of which are unmanned, will be extremely time consuming and ultimately may not be accurate. In many (if not nearly all) instances, and as indicated above, electricity purchasers do not own nor control the meters in use at a site; those meters may be replaced or changed by the energy provider without any notice to the electricity purchaser. Therefore, not only is this requirement extremely time consuming for the reporters, it would also fail to meaningfully improve the quality of reported data and the reported information could become outdated without the knowledge of the reporter.

Additionally, as proposed, 40 CFR 98.26(f) requires operators to report several pieces of data for each meter for each bill received. This requirement will be extremely burdensome while failing to increase transparency in reporting. For the oil and natural gas industry, this could require reporting hundreds, if not thousands, of individual meters. As described above, meters can be changed by the energy provider, with or without the purchaser's knowledge, throughout the course of the reporting period. Such meter changes could result in a Designated Representative (DR) certifying a report that may not be accurate as of December 31st of the reporting period[3]. As these meter numbers can change, requiring electricity purchasers to provide this level of detail does not increase EPA's ability to review or otherwise QA/QC the reported data, while still significantly increasing the burden of reporting on energy purchasers. Finally, the requirement to report meter location information to the county/city level can become very complex for facilities operating across a wide geographical area. The Industry Trades are respectfully recommending the removal of this reporting requirement.

[3] As required in 40 CFR Part 98.4(e), each Designated Representative signs the following certification statement: "I am authorized to make this submission on behalf of the owners and operators of the facility or supplier, as applicable, for which the submission is made. I certify under penalty of law that I have personally examined, and am familiar with, the statements and information submitted in this document and all its attachments. Based on my inquiry of those individuals with primary responsibility for obtaining the information, I certify that the statements and information are to the best of my knowledge and belief true, accurate, and complete. I am aware that there are significant penalties for submitting false statements and information or omitting required statements and information, including the possibility of fine or imprisonment."

EPA is also proposing reporters to include a "description of the portions of the facility served by the meter." As described above, this requirement would encompass hundreds of meters across a wide geographical area which could change with or without the purchaser's knowledge. This requirement is also burdensome at complex facilities, such as refineries, which may purchase electricity to supplement on-site electricity generation.

The Industry Trades believe these reporting requirements to be overly burdensome and ultimately do not increase the transparency or quality of reported data.

Submitting Sample Energy Bills

As proposed in 40 CFR §98.26, reporters are required to provide EPA with copies of one direct billing statement from each provider. The Industry Trades are concerned these statements could include confidential business information (CBI) relating to purchase agreements, rates, and thermal energy usage. It is also unclear why EPA needs reporters to submit these records; EPA does not have analogous requirements in other subparts to submit example raw data in the form of bills or invoices to validate the reported data.

Additionally, for operators with a large number of sites across a large geographical area, the proposal could require multiple providers to upload hundreds of pages of billing statements. As a practical matter, users of EPA's Electronic Greenhouse Gas Reporting Tool (EGGRT) have experienced delays in using the system when many reporters are using the system simultaneously; this seemingly simple task could result in very time intensive uploading requirements during a reporting period. Furthermore, as previously mentioned, reporters are not required to submit this level of documentation for other subparts, but instead follow the recordkeeping requirements codified in 40 CFR and the appropriate subparts. The Industry Trades support that same approach for Subpart B.

Allow Subpart W Reporters to Submit All Subpart W Segment's Energy Consumption at a AAPG Hydrocarbon Basin Level

The Industry Trades recommend that EPA allow reporters subject to reporting under Subpart W to report energy consumption for all GHG reporting activities within a single AAPG hydrocarbon basin without direct upload of billing statements. The Subpart W operations are often interconnected, and many operators report under production, gas processing and gathering and boosting segments. In addition, electric meters may service an entire basin, a single site, or multiple sites. In order to report at a source category level as defined in Subpart W, operators would need to allocate metered electricity to a single site and then reallocate back to a segment. This would be extremely burdensome and does not meaningfully improve the quality of reported data. This gives reporters the ability to maintain relevant energy consumption information in existing Greenhouse Gas Monitoring Plans, as already required in 40 CFR 98.3(g)(5) and other relevant subparts. As currently codified, this information would be available upon request by EPA.

Missing or Incomplete Billing Information

It is not uncommon for some billing information to not be finalized for up to six- months or longer. As a result, there could be instances where complete billing information may not be available by the reporting deadline for the complete prior calendar year. The Industry Trades request that EPA allow for the use of best information available or other reasonable estimation methods to estimate partial-year energy consumption when a full calendar year of billing is unavailable.

Renewable Energy Credits and Energy Consumption

As EPA has acknowledged in the preamble to the supplemental proposal, this method of reporting energy consumption does not provide the EPA with information on renewable energy credits (RECs) that allows reporters to net Scope 2 emissions commensurate with purchased and retired RECs. The lack of data collection and transparency on renewable energy attributes may inadvertently disincentivize the purchase of renewable energy altogether. The Industry Trades recommend that in addition to reporting the energy consumption, that EPA allows reporters to voluntarily report the amount of energy that is sourced from retired RECs or a renewable energy purchase agreement. This will provide the public and other stakeholders with a more complete picture of overall GHG emissions intensity.

Annual Data Only

EPA is proposing to collect data for every bill and every meter. For example, if the meter is billed monthly, EPA is requesting monthly data. The Industry Trades recommend that EPA remove any requirements to report data more granular than annual data. It is unclear how EPA could even use monthly purchased energy data to assess facility energy intensity. The onerous reporting requirements proposed in this new subpart indicates that EPA believes it can apply automatic checks to ensure all energy consumption bills are as expected and accounted for, the number of expected bills are reported (billing sequence), and that start dates and end dates align. However, given the wide range of energy providers, facility types, geographic locations and other factors, this assumption is incorrect. Bills are subject to billing corrections, rebills, negative usage bills to handle calibration errors, higher-than-previous usage to correct calibration errors; bills with zero usage to handle payment adjustments, overlapping start and end dates, some bills that cover two months instead of one, meters going into service, meters coming out of service, etc. It will be an enormous burden to report detailed information from every bill, EPA has not justified this effort, and EPA will likely burden reporters with error checking for very typical billing inconsistencies. For all of these reasons, EPA should collect annual data only.

Exempt Subpart B Reports from "Substantive Error" Provisions in 40 CFR Part 98 Subpart A

EPA's definition of "Substantive Error[4]", which would trigger resubmittal of applicable GHG reports, is overly broad for this subpart as it does not have a *de minimis* threshold. There can be adjustments to energy consumption records several months following the closing period of the billing cycle. These adjustments could result in an operator having to re-submit reports previously certified even if the adjustment does not result in a significant change in the reported energy consumption. This is especially problematic for the oil and natural gas industry because of the huge number of meters potentially subject to Subpart B, the large number of meters, adjustments, etc. which may not have a substantive impact on overall energy consumption. The Industry Trades request that EPA does not subject Subpart B reports to the "Substantive Error" provisions, as defined in 40 CFR Part 98 Subpart A.

Purchased Thermal Energy Reporting

As proposed, Subpart B requires reporting metered thermal energy products as well as comprehensive auditing requirements for thermal energy meters.

a. Consistent with the comments above, it is the Industry Trades' position that the purchaser should not be required to provide the most recent accuracy audit; instead, that should fall to the energy provider as the owner of the meter.

b. The Industry Trades object to the proposed requirement that a purchaser must conduct the audit on a thermal meter system where purchasing agreements do not include provisions for periodic audits under 40 CFR 98.24(c). Regardless of who is responsible for an audit on a thermal meter system, the Industry Trades request that EPA

[4] Substantive error, as defined in 40 CFR 98.3(h) means, "an error that impacts the quantity of GHG emissions reported or otherwise prevents the reported data from being validated or verified."

clarify minimum requirements to be considered a "qualified metering specialist" under 98.24(c) and any restrictions to using in-house resources (i.e., facility, energy provider, independent resources, etc.).

c. The Industry Trades request flexibility regarding the 5-year audit requirement for purchased thermal energy meters. As proposed, 98.24(c) states that if the audit has not been performed (or is older than 5 years old), the energy purchaser is to request an audit from the energy provider. However, this audit procedure can only be completed during a facility shut-down or plant turnaround. The Industry Trades request that EPA add language that allows for this audit to take place either every 5 years or during the next planned unit shut-down.

d. In 98.24(a)(6) and 98.26(j)(2), EPA is proposing that the reporter be responsible for developing a "clear procedure" and example of how measured data are converted to mmBTU. By putting the onus on the reporter to develop "clear procedures," the potential for a wide range in methods and results exists, thus calling into question the value and necessity of reporting thermal energy consumption. For example, there may be differences in how reporters quantify hot and cold energy products (i.e., positive vs. negative value), based on the purpose to add or remove thermal energy. As a result, some reporters may net thermal energy while others sum the absolute values, leading to very different results. The Industry Trades recommend that EPA clarifies how thermal energy measurements should be converted to mmBTU, and the Industry Trades also recommend adding a reporting field for both cold and hot energy products in the reporting form.

e. As proposed, Subpart B provisions for thermal energy reporting only address the purchased energy, which may not represent the energy consumed on-site. The Industry Trades propose reporting this information on a facility-wide net-energy basis. Many facilities that purchase steam also return condensate, which has embodied energy that is not consumed at the purchaser's facility. Also, some facilities that utilize electrical and/or thermal energy from a provider may pass through some of the energy purchased to a third party. In order for EPA to understand the energy consumed at the facility, both thermal energy purchased and condensate returned or energy passed through need to be understood. The Industry Trades believe that reporting this information on a net-energy use basis will provide clearer information regarding thermal energy usage.

f. The Industry Trades also request EPA to remove, or at least provide clarification/guidance regarding, the requirement to assign the decimal fraction of purchased energy to applicable GHGRP Subparts under 98.26(l) for larger integrated facilities that utilize multiple external electrical/thermal connections with on-site energy generating units or thermal production units, as it would be overly burdensome to reasonably segregate and calculate purchased energy from site generated energy with any reasonable confidence due to the fluid nature of imported and exported energy across a large facility. Similarly, guidance of scenarios on calculating excluded quantities under 98.26(j)(4) would be valuable for the regulated community as purchasing/selling of energy may overlap based on energy loading across the larger integrated facilities and surrounding community.

g. The definition of thermal energy that states "or any other medium used to transfer thermal energy and delivered to a facility" is overly broad and ambiguous. For example, it is unclear if purchased raw water utilized as cooling tower make-up water would be subject to the requirements, even though there may be no associated indirect emissions. The Industry Trades request clarification of the definition of thermal energy to only include thermal products where the primary reason for purchase is energy transfer and where energy was required to achieve a specific thermal property for the purchased products prior to metering. Similarly, the Industry Trades recommend incorporation of a reference temperature (e.g., outside of ambient) to define thermal energy products to avoid confusion.

h. Likewise, EPA's proposed definition of thermal energy also includes refrigerants. Clarification should be made that this excludes non-industrial process uses such as refrigerants for comfort cooling and food storage. In most cases these are not "metered," but this exclusion would avoid confusion. The Industry Trades respectfully recommend adding the proposed language ***in red*** below:

   "Thermal energy products means metered steam, hot water, hot oil, chilled water, refrigerant, or any other medium used to transfer thermal energy and delivered to a facility subject to this subpart. ***Thermal energy products do not include those used for non-industrial purposes such as comfort heating/cooling and food storage/preparation."***

Additional Comments Sought by EPA:

EPA is seeking comment on existing industry standards for assessing the accuracy of electric and thermal energy monitoring systems, the frequency of audits of these systems, and the accuracy specification(s) used for thermal energy product metering systems. Consistent with the Industry Trades' position on the meter-level QA/QC and accuracy requirements, the Industry Trades' members are not generally energy providers and cannot comment on the accuracy of electrical and thermal energy monitoring systems. However, it is the Industry Trades' position that any audits of these electric and thermal energy monitoring systems be performed only during a planned facility shut-down.

EPA is also seeking comment on their understanding that monitoring and recordkeeping systems are already in place for purchased energy transactions and on EPA's assessment that the incremental reporting burden would be minimal. As reflected in the comments in this section, the Industry Trades believe that the recordkeeping and QA/QC requirements as proposed would be extremely burdensome for operations across large geographic areas, such as oil and natural gas operations.

2. Subpart WW – Coke Calciners

The proposed Subpart WW includes two proposed calculation methods to determine the CO_2 emissions from coke calciners in section 40 CFR §98.493(a). The first method uses the Tier 4 method that requires Continuous Emissions Monitoring Systems (CEMS) and requires a stack flowmeter. Stack flowmeters on coke calciners can be unreliable and can be difficult to maintain while the unit is operating. Coke calcining units that do not currently have a stack flowmeter would need to purchase, install, maintain and calibrate them, which could be a cost in excess of the Capital and O&M costs given in Table 10 for an incremental burden.

The second method is a carbon balance based on the mass and composition of the green carbon feed, petroleum coke dust and marketable coke produced. Coke calcining units that do not currently weigh all of these streams or conduct regular sampling could be required to install new scales and collect and analyze samples which may again require expenditures in excess of the incremental burden costs estimated in Table 10. There may be issues getting the carbon mass to balance, as uncertainties in weights and coke composition could lead to under or overestimation of CO_2 emissions.

There is a third method, currently used at a coke calcining unit and currently used to comply with a Washington State GHG Reporting program, that should be included as an approved method in Subpart WW section §98.493(a). In this method a performance test is conducted to measure the stack flow while the CO_2 and O_2 concentrations are measured using a CEMs system, and either the green coke input or calcined coke output is weighed. The result of the performance test is to determine the coke calciner stack flow based on either green carbon input or marketable coke output. This allows the CO_2 emissions for each hour of the year to be calculated using the weighed coke input or output, the CEMs CO_2 and O_2 concentrations and the stack flow factor from the performance test. The performance test is conducted periodically and the factor from the last test is used until the next stack test is performed. The stack flow factor is corrected to a set excess oxygen concentration, and the CEMs data measured throughout the year to allow the measured CO_2 concentration to be corrected to the same excess oxygen concentration.

This third method combines elements from both of the methods currently included in the proposed Subpart WW. It has an advantage that use of a stack flow factor prevents potential large periods of data substitution when the stack flowmeter is not operating. The Industry Trades request that EPA add this third method to the proposed Subpart WW. The addition of an alternate State approved method is consistent with provisions that the EPA has previously made in the Tier 4 methodology in 40 CFR 98.34(c)(1)(iii) and 40 CFR 98.36(e)(2)(vii)(A) that allow a State approved monitoring program.

Summary

The undersigned associations, representing the oil and natural gas industry, appreciate EPA's willingness to collaboratively engage with the regulated community in order to improve the quality and consistency of reported data while also streamlining the reporting process. The comments provided in this letter are intended to support this effort by providing EPA with additional context and potential unintended consequences associated with some of the proposed reporting, recordkeeping, and QA/QC requirements.

The Industry Trades are working to reduce GHG emissions across the value chain of the oil and natural gas industry, and it is critical that the EPA and the GHGRP reflect accurate reporting of GHG emissions. To that extent, it is important that EPA carefully consider these proposed revisions and new subparts and consider the points outlined by the Industry Trades while considering future proposed rulemaking.

The undersigned associations encourage EPA to carefully consider the comments and recommendations contained within this letter, and we stand ready to respond to questions and provide further clarifications, as needed, from EPA. For more information, please contact Jose Godoy at Godoyj@api.org or 202-682-8073.

Sincerely

Jose Godoy
Policy Advisor, Climate & ESG
American Petroleum Institute

Wendy Kirchoff
Vice President, Regulatory Policy
American Exploration & Production Council

C. Jeffrey Eshelman, II
President & Chief Executive Officer
Independent Petroleum Association of America

Angie Burckhalter
Sr. V.P. of Regulatory & Environmental Affair
The Petroleum Alliance of Oklahoma

Evan Zimmerman
Executive Director
Offshore Operators Committee

CC: Chris Grundler, Director for Office of Atmospheric Programs, EPA
Mark DeFigueiredo, Office of Atmospheric Programs, EPA

ANNEX C: API Comments on EPA's Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources" Oil and Natural Gas Sector Climate Review, Submitted February 13, 2023

American Petroleum Institute

Frank J. Macchiarola
Senior Vice President
Policy, Economics and Regulatory Affairs

200 Massachusetts Avenue, NW,
Suite 1100
Washington, DC 20001-5571
202-682-8167
Macchiarolaf@api.org

Submitted via regulations.gov

February 13, 2023

The Honorable Michael S. Regan, Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W. Washington, D.C. 20460

Attention: Docket ID EPA-HQ-OAR-2021-0317

RE: Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, Including Appendix K and Social Cost of Greenhouse Gases

Dear Administrator Regan:

The American Petroleum Institute (API) respectfully submits the attached comments on the Environmental Protection Agency's (EPA) Supplemental Proposal "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (87 FR 74702, December 6, 2022) ("Supplemental Proposal"). This submittal includes comments on the associated Appendix K proposal and EPA's "Report on the Social Cost of Greenhouse Gases".

API is the national trade association representing America's oil and natural gas industry. Our industry supports more than 11 million U.S. jobs and accounts for approximately 8 percent of U.S. Gross Domestic Product (GDP). API's nearly 600 members, from fully integrated oil and natural gas companies to independent companies, comprise all segments of the industry. API's members are producers, refiners, suppliers, retailers, pipeline operators, and marine transporters, as well as service and supply companies, providing much of our nation's energy. API was formed in 1919 as a standards-setting organization and is the global leader in convening subject matter experts across the industry to establish, maintain, and distribute consensus standards for the oil and natural gas industry. API has developed more than 700 standards to enhance operational safety, environmental protection, and sustainability in the industry.

As we indicated in our comments on EPA's November 2021 Proposal (86 FR 63110, November 15, 2021), API supports the cost-effective, technically feasible, direct federal regulation of methane from new and existing sources across the supply chain. We appreciate EPA's further development of a fugitive emissions monitoring framework that allows for use of advanced detection technologies. We also appreciate EPA's recognition that Appendix K's monitoring protocol is not appropriate for the upstream production and transmission segments. While we appreciate EPA's responsiveness to many of the issues raised in our comments[1] on the November 2021 Proposal, nevertheless, we have serious concerns regarding the cost effectiveness, technical feasibility, and legal soundness of many aspects of the Supplemental Proposal. We also have extensive concerns with EPA's Draft Report on the Social Cost of Greenhouse Gases and the lack of transparency in the Interagency Working Group's process. Moreover, we strongly disagree with EPA's assertion[2] that November 15, 2021 can serve as the applicability date of the final rule for new, reconstructed, and modified sources.

Reducing methane emissions is a shared priority for EPA and our industry. We are committed to advancing the development, testing, and utilization of new technologies and practices to better understand, detect, and further mitigate emissions. In recent years, energy producers have implemented leak detection and repair (LDAR) programs, phased out the use of high-bleed pneumatic controllers, and reduced emissions associated with flaring – voluntarily and under federal and state regulations. Voluntary, industry-led initiatives such as The Environmental Partnership[3] have built on the progress industry has made to reduce emissions and continuously improve environmental performance. Since its founding in 2017, the Partnership has grown to include over 100 companies representing over 70% of total U.S. onshore oil and natural gas production.

The New Source Performance Standards (NSPS) OOOOb and Emissions Guidelines (EG) OOOOc are complex rules that will apply to hundreds of thousands of facilities owned and operated by these and other companies, including many facilities that have not previously been subject to regulation under the Clean Air Act. Because of the wide variety of conditions faced by these facilities, the novel nature of a first ever existing source rule, and timing of the Supplemental Proposal's release and subsequent overlap with the holiday season, API requested[4] an extension of the comment period to allow additional time for our staff and our members to fully review the Supplemental Proposal and provide EPA with well-developed information necessary to promulgate an environmentally protective, technically feasible, and cost-effective rule. As we noted, API members who are engaged on this issue have been concurrently engaged in reviewing additional recent legal and regulatory developments on this subject matter. We regret that EPA did not grant the request and may rush to completion of a final rule that does not reflect the full measure of consideration necessary to ensure cost effectiveness, technical feasibility, and legal soundness.

In our review of the Supplemental Proposal, API once again considered the effectiveness of emission reduction strategies, safety, feasibility, operability, and cost. Where appropriate, we have recommended changes to the regulatory text that will enable the final rule to meet these critically

[1] EPA-HQ-OAR-2021-0317-0808
[2] 87 FR 74716
[3] http://www.theenvironmentalpartnership.com
[4] EPA-HQ-OAR-2021-0317-1588

important criteria. We have also detailed the necessity of workable implementation timelines that consider the supply chain and labor constraints facing our industry, constraints which will be exacerbated as the final rule takes effect. The adoption of the recommendations in our comments in the final rule would reflect a more cost-effective and technically feasible regulation of methane.

API appreciates EPA's engagement and responsiveness to our questions during the comment period. We remain committed to working constructively with EPA and the Administration to finalize a cost-effective rule that incentivizes innovation, advances the progress made in reducing emissions and addressing climate change, and ensures that our industry can continue to provide the world with the affordable, reliable energy it requires.

If you have any questions regarding the content of these comments, please contact Ryan Steadley at steadleyr@api.org.

Sincerely,

cc:

Joe Goffman, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Karen Marsh, EPA
Steve Fruh, EPA
Amy Hambrick, EPA

API Comments on EPA's Proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review"

(Proposed NSPS OOOOb, EG OOOOc, Appendix K and the Social Cost of Greenhouse Gases)

Docket ID: EPA-HQ-OAR-2021-0317

February 13, 2023

Executive Summary

The American Petroleum Institute (API) supports certain aspects of the Supplemental Proposal for New Source Performance Standards (NSPS) OOOOb and Emissions Guidelines (EG) OOOOc and remains committed to working with the Environmental Protection Agency (EPA) and the Administration to identify cost-effective emission control opportunities. The comments provided herein focus on legal, technical, and feasibility challenges with specific provisions that EPA included within the Supplemental Proposal of NSPS OOOOb and EG OOOOc. Listed below are API's primary concerns with the proposed rules.

To facilitate review of our comments, API has summarized these concerns and provided reference to the detailed comments where additional supporting discussion has been included. Our members look forward to continued dialogue and engagement as EPA works towards finalizing these important rules.

1) **The Applicability Date for NSPS OOOOb should be December 6, 2022.**
   The Clean Air Act (CAA) Section (§) 111(a)(2) definition of "new source" uses the term "proposed regulations" in defining the new source trigger date. The November 2021 preamble alone cannot constitute a proposed rule any more than a final rule that is unaccompanied by regulatory text could be declared a "rule." Although the November 2021 preamble described the type of regulatory requirements that EPA contemplated promulgating, the preamble was not in and of itself a document that establishes the "agency statement of general or particular applicability and future effect." That type of required statement would be established only by the proposed regulatory text, which was not provided until the December 2022 Supplemental Proposal. Many of the requirements included in the proposed regulatory text could not have been gleaned from the prior descriptions provided. Refer to Comment 8.1 and Comment 12.1.

2) **Adequate implementation time must be provided for NSPS OOOOb and EG OOOOc.**
   NSPS OOOOb and EG OOOOc will apply to hundreds of thousands of sites when implemented. Our members are already experiencing a noticeable delay in the supply chain for equipment required by the proposed rules including (but not limited to) control devices, flow monitoring equipment, instrument air systems, solar panels, etc. Control devices are currently experiencing delays of 3 to4 months, while flow monitors are on backorder for a minimum of 6 to8 months from suppliers. Instrument air systems (including the air compressor and associated equipment) are nearly 1 year on backorder, and recently ordered solar panels are delayed between 18 to24 months. As more facilities become subject to proposed requirements in NSPS OOOOb and EG OOOOc, the above timelines are anticipated to be exacerbated before the market experiences a correction to meet these new levels of demand. We provide more detail related to current supply chain delays in Comment 5.2 and Comment 7.1. We request EPA consider these challenges prior to finalization of certain provisions within these rules to allow operators the ability to acquire and install the required equipment. Additionally, EPA should allow more time for new, modified, and reconstructed sources to come into compliance with NSPS OOOOb if it maintains the current applicability date of November 15, 2021.

3) **Associated gas provisions need to be significantly modified.**
Whereas API supports and recognizes the environmental benefit of eliminating the venting of associated gas from oil wells, EPA must recognize the distinction between associated gas from oil wells that route to a sales line and oil wells that do not have adequate or accessible gas gathering infrastructure. Removing wells connected to sales lines (or recovering gas for another primary purpose) from the requirements of the associated gas provisions would help to eliminate confusion resulting from EPA introducing its own interpretation of "flaring" when multiple definitions of "routine flaring" already exist in state and voluntary programs. Additionally, API does not support the requirement to make an infeasibility demonstration, along with safety and technical certifications in order to flare associated gas. Refer to Comment 4.0. and Comment 12.9.

4) **As proposed, the Super-Emitter Response Program presents numerous legal, logistical, commercial, safety, and security risks that have not been adequately considered by EPA within the Supplemental Proposal.**
To address these concerns (and assuming EPA resolves the legal deficiencies), numerous adjustments to the proposed framework are necessary. Specifically, EPA must establish requirements for monitoring of third-party data, provide a formal notification process that includes EPA involvement and review, and provide limitations on how any monitored data is released and used publicly. Refer to Comment 1.0, Comment 12.3, and Comment 12.4.

5) **In determining storage vessels affected facility Potential to Emit, EPA's proposed criteria for legally and practicably enforceable limits have broad legal implications and pose several permitting challenges.**
The proposed criteria and the additional methane emissions threshold may be lacking in existing permits that have previously been understood to be legally and practicably enforceable and may also be impossible to obtain under existing permitting mechanisms. EPA should continue to defer to the states on sufficient monitoring, recordkeeping, and reporting requirements to include in permits to establish legally and practicably enforceable limits. API also offers suggestions concerning various definitions and proposed control requirements for storage vessels affected facilities. Refer to Comment 6.0. and Comment 12.10.

6) **As proposed, alternative technology requirements for fugitive emissions monitoring, including continuous monitoring, are impractical and may disincentivize the use of this emerging technology.**
API recognizes and appreciates EPA's initial and important efforts in creating a framework for alternative leak detection technologies, including continuous monitoring, in NSPS OOOOb and EG OOOOc. However, we urge EPA to make key adjustments in the final rule to enhance the use, and not unintentionally disincentivize development and deployment of these technologies. In particular, we believe there should be approved technologies for operators' use at the time the rule is finalized, alternate technologies should not be held to a greater level of stringency (i.e., frequency) than Best System of Emission Reduction (BSER) as currently proposed, and EPA should streamline the timeline and actions to conduct repairs. Refer to Comment 3.0.

7) **API proposes AVO inspections only at multi-wellhead only sites.**
EPA's focus on finding large fugitive emissions at single wellhead only sites using audio, visual, olfactory (AVO) inspections is appropriate and should also apply to multi-wellhead only sites. An AVO inspection is the most appropriate tool to rapidly identify large emissions at wellhead only sites. While wellheads are a source of emissions, various studies indicate wellhead emissions amount to a very small share of overall

well site emissions. Given wellhead only sites number in the tens of thousands, the prudent and most efficient use of resources is to focus on detecting the rare occurrence of large fugitive emissions from wellheads, which can be accomplished with AVO inspections. Refer to Comment 2.1.

8) **EPA should clarify its preamble language concerning leaks detected from a cover or a closed vent system during associated inspections or other fugitive emissions monitoring.**
Emissions detected from covers and closed vent systems do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented. Like standards for other fugitive emissions components, the "no identifiable emissions" standard is a work practice standard rather than a numerical emissions standard. Therefore, EPA must make it clear that a cover or closed vent system remains in compliance when a leak is detected, provided the associated work practices requiring investigation and repair are followed. Regarding control devices, API recommends a compliance extension of at least one year for the proposed monitoring requirements. We also offer suggestions to provide consistency between manufacturer-tested devices and other enclosed combustion devices as well as request EPA provide the necessary monitoring alternatives given the increased number of control devices subject to proposed monitoring requirements. Refer to Comment 5.0.

9) **EPA should amend many of the provisions within the Supplemental Proposal to work practice standards and eliminate the additional technical demonstrations with accompanying certification statements.**
EPA has added several certification statements throughout the proposed requirements for NSPS OOOOb and EG OOOOc – including certifications for pneumatic pumps, gas well liquids unloading operations, and associated gas from oil wells. EPA has not asserted an adequate legal basis for identifying non-emitting techniques as BSER and establishing them as a standard, but at the same time creating exceptions that require technical demonstrations and engineering certification. Inclusion of these technical infeasibility exceptions to the proposed non-emitting standards indicates that the non-emitting standards are not permissible under CAA § 111 because non-emitting standards are not "adequately demonstrated" if exceptions are needed to make them feasible and workable. Regarding the certification statements themselves, a certified official is already required to sign the report certifying the company's compliance with all applicable provisions. These additional certifications should be removed prior to finalization of these standards for associated gas from oil wells, pneumatic pumps, and gas well liquids unloading operations. Refer to Comment 4.1, Comment 8.2, Comment 9.1, Comment 10.1, and Comment 12.9

10) **Requirements for pneumatic controllers and pneumatics pumps should be simplified and aligned.**
While we support EPA's proposal for defining the affected facility for both pneumatic controllers and pumps as the collective, we have numerous concerns with the practical and logistical aspects of how EPA has outlined control standards between the two sources. Specifically, EPA has proposed a completely distinct set of requirements for natural gas-driven controllers separate from natural gas-driven pneumatic pumps with sometimes conflicting statements made to justify EPA's decisions. The requirements for both pneumatic controllers and pumps should be streamlined for consistency with neutral technology standards that do not require additional certifications and allow for emissions to be routed to a control device. Refer to Comment 7.0 and Comment 8.0.

11) EPA should streamline the recordkeeping and reporting requirements associated with compliance assurance of the proposed rules.

EPA should continue to streamline both recordkeeping and reporting as it relates to these proposed requirements to include only the necessary information that will help assure compliance. Streamlining is especially critical for locations with existing sources as the cumulative impacts for tracking records are anticipated to be much larger than EPA estimates and will apply to hundreds of thousands of sites across the U.S. For some sources, EPA has described requiring records and potential reporting of information that does not link directly to emission controls or work practices, which API does not support. We support inclusion of recordkeeping and reporting that help demonstrate compliance with less administrative burden. Refer to Comment 9.3 and Comment 13.2.

12) EPA should grant equivalency for state programs across emission sources for NSPS OOOOb and EG OOOOc.

Given EPA has described many requirements that are consistent with those at the state level (e.g., Colorado, New Mexico, and California), EPA should allow for certain state provisions to be deemed equivalent for the proposed NSPS OOOOb and EG OOOOc where it is appropriate to do so for leak detection and repair (fugitive emission monitoring) and other emission control provisions. EPA should allow states the opportunity to demonstrate programmatic equivalency, including addressing deviations from the form of the proposed standards. Without this, states and operators may be administering and complying with two sets of requirements (standards and administrative) that are duplicative because they are intended to achieve similar goals but are not perfectly identical. It also precludes innovative regulatory approaches from states. Refer to Comment 12.6 and Comment 12.7.

13) EPA should carefully consider the overlapping applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc in conjunction with the cumulative burden imposed through provisons in the Supplemental Proposal.

EPA must consider the cumulative burden imposed to the regulated community of numerous and onerous provisions in the Supplemental Proposal, especially due to the unprecedented number of sources that will be subject to the rule given the proposed November 2021 applicability date for new, modified, and reconstructed sources. EPA must also consider the overlapping applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc and the difficulty the industry has faced to fully understand the impacts of this rule without a comment extension. These difficulties for the regulated community have been compounded by other rules that impact the same sources (e.g., Bureau of Land Management's (BLM's) Waste Prevention Proposal). Specifically, EPA needs to be clear on the disposition of NSPS OOOO and OOOOa applicable sources if and when they become subject to EG OOOOc. Finally, EPA must revise its Regulatory Impact Analysis, including the potential for lost production stemming from implementation of these rules. Refer to Comment 12.1 and Comment 12.5.

14) For equipment leaks at onshore natural gas processing plants, API recommends that closed vent systems be monitored annually and that appropriate VOC and methane concentration thresholds be established for applicability.

While API supports the proposed bimonthly OGI monitoring as well as the proposed alternative monitoring based on the incorporated NSPS VVa requirements with simplifications, we have concerns with the proposed frequency for closed vent systems and the proposed potential to emit applicability threshold for VOC. While we generally support the proposed Appendix K for OGI monitoring at gas plants, we have several comments regarding proposed Appendix K as provided in Attachment A. Other comments on leak detection and repair at gas plants include our recommendation on the proposed definition of equipment for capital expenditure evaluations. Refer to Comment 11.0 and Attachment A.

15) **API appreciates EPA's decision to accept comments specifically on the EPA's Social Cost of Greenhouse Gas (SC-GHG) Report, but we have a number of questions and concerns about EPA's unilateral development of SC-GHG estimates.**
API shares the Administration's goal of reducing economy- wide GHG emissions. With respect to SC-GHG our concerns stem from the approach taken by EPA, including the anticipated role of these new estimates in EPA's rulemaking, and the SC-GHG Report's apparent inconsistency with the Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the Interagency Working Group. Refer to Comment 13.5 and Attachment B.

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Attachment B – Comments on the EPA's Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances

PROPOSED NSPS AND EMISSIONS GUIDELINES FOR THE OIL AND NATURAL GAS SECTOR (NSPS OOOOb AND EG OOOOc) INCLUDING APPENDIX K DOCKET ID: EPA-HQ-OAR-2021-0317

While we have made every effort to thoroughly review both proposed New Source Performance Standard (NSPS) OOOOb and Emission Guidelines (EG) OOOOc as we formulated these comments, there may be places where we only provide a citation or reference as it pertains to proposed regulatory text in NSPS OOOOb. Unless we have provided a distinctly separate comment as the topic pertains to EG OOOOc, we also intend the comment to apply to proposed EG OOOOc. Additionally, when using the terms "proposal" or "standards" in these comments in reference to the November 2021 preamble, it does not constitute a "proposed rule" or "emission standard" for purposes of triggering applicability under CAA § 111(a)(2).

1.0 Super Emitter Response Program

As proposed, the Super Emitter Response Program (SERP) presents numerous legal[5], logistical, commercial, safety, and security risks that have not been adequately considered by the EPA and are the basis for the comments we offer herein. These complex issues would benefit from further discussions between EPA, operators, and other interested parties.

Our members understand the importance of identifying and addressing large emissions events and any future support for a program would be grounded in a shared interest to reduce the incidence of these emission events. For over three decades, EPA and industry have successfully collaborated on the implementation of voluntary programs to reduce methane emissions from the oil and natural gas sector under both the Natural Gas Star and Methane Challenge Programs. While we believe the SERP may be better suited to function as a voluntary based program, API members recognize the intent of the EPA to create a useable and workable program that identifies these large emissions events from a variety of stakeholders.

We encourage EPA to conduct additional outreach on the proposed framework and repropose a program that meets all Clean Air Act legal requirements prior to finalizing the requirements (as provided in §60.5371b). Our members would welcome the opportunity for future discussions on this important topic.

1.1 API proposes a programmatic framework that is managed by EPA and incentivizes the finding and subsequent repair of potential super emitter emission events.

EPA has described the SERP as a backstop to the requirements of NSPS OOOOb and EG OOOOc. However, as we describe throughout our comments there are serious legal, logistical, commercial, safety, and security problems inherent in EPA's proposed program. The framework we have described herein achieves the goals EPA has described for the program while addressing the concerns API members have with EPA's proposal.

[5] See Comment 12.3 and 12.4 of this letter for a discussion of the numerous legal deficiencies underpinning the proposed SERP.

For the SERP to be effective, EPA must reconsider the operational flow of how the program will function and be implemented. This framework includes adding formal notifications first from third parties to EPA and then from EPA to operators. We also specifically offer suggestions on clear timelines for all participants of the program where information can be transferred in a clear and transparent order, which we have emphasized in our framework.

Below we have outlined our suggestions on the appropriate steps to be included in a reproposed framework, which provides greater confidence that the data provided under the program will be valid, actionable, and achieve EPA's goals for transparency within the program.

1) The third party completes approval certification process by EPA for inclusion in the Super-Emitter Response Program and becomes "certified or re-certified".
2) Certified third party[6] notifies EPA of planned monitoring, including submittal of a monitoring plan, at least **30 business days** prior to planned monitoring. Depending on technology deployed, such as satellites, this pre-approval may include flight plans for extended time periods. The components of the monitoring plan are more fully described in Comment 1.1.3 of this letter.
3) EPA reviews the certified third parties' monitoring plan for approval or disapproval.
    a. If approved, EPA notifies the impacted operators at least **7 business days prior** to monitoring with details of the monitoring to be conducted including technology planned for use, dates of monitoring, flight paths (if appropriate), etc. This notice essentially acts as a "pre-notification" to operators, which enables the operator to have staff available to ensure safety of operations, if warranted based on technology that will be used to detect potential emissions by a third-party.
    b. This "pre-notification" may also help both EPA and the third-party identify the appropriate operators, including the correct contact information, in the event a super emitting emissions event is detected. The potential for incorrect identification of operators is of concern for our members.
4) Timing of notification of results of monitoring to the operator is critical to the effectiveness of the SERP. After monitoring is completed, third party has **2 calendar days** to provide data as defined in §60.5371b(b) to the EPA.
5) If EPA determines the data provided by the third-party to be credible and warrants investigation, EPA provides data for any super emitter emission event to the appropriate operator(s) within **3 calendar days** of verification of third-party monitored data.[7]
6) Operator(s) will initiate an investigative analysis **within 5 business days** of receipt of data from EPA and complete the investigation within **10 business days** of receipt of the data from EPA.
    a. Given how certain technology is applied, the detection may not be from the facility that was notified, may be a permitted release, may be due to maintenance activity, or another reason that does not require action (such as monitoring data calibration issue). If the emissions event was the result of a permitted activity or could not be validated after full investigation by the operator, the

[6] For the purpose of these comments when we reference a 'third-party', "certified notifier" or 'certified third-party' we mean the certified individual and the monitoring company whose technology is utilized to conduct monitoring.
[7] The basis for the timing proposed in steps 4 and 5 is to align with what EPA has proposed for operators using similar technology.

operator will provide "no action required" demonstration to EPA as specified in §60.5371b(c)(8) and §60.5371b(e)(1).

b. If the emissions event was result of component failure or other equipment defect, the operator(s) will complete final repairs **<u>within 15 calendar days</u>** after completing the investigative analysis.

7) All public information should be published by EPA only. EPA should manage all data that is to be public and establish a protocol for when and what type of specific details of a potential super-emitter emissions event is published via EPA's proposed website per §60.5371b(e)(4). We strongly disagree with the assertion in Section IV.C.2.a of the preamble (87 FR 74750) which states "*The EPA would then promptly make such reports available to the public online. Third parties may also make such reports available to the public on other public websites. The EPA would generally not verify or authenticate the information in third party reports prior to posting.*" Given that much of the data collected can be interpreted incorrectly and not aligned with operating conditions, the EPA should be the only authority to publish data, and EPA should publish data only after operators have had an opportunity to review and respond to the information and EPA has fully reviewed and vetted follow-up actions with the operator.

The timing of each step in the above framework has been crafted with the intent that all participants are held to timelines that are workable and suitable for each step of the framework. Operators are concerned they could receive multiple third-party notifications with limited time and resources to respond appropriately if stricter timing criteria for third parties to provide data is not established. The above framework seeks to address this concern.

1.1.1 EPA should establish transparent certification requirements for third-party monitoring.

Two-way accountability will allow for efficient and effective execution of the super-emitter response program. EPA should develop a clear set of criteria (e.g., in a checklist form) that any certified third-party would need to meet to participate in the program. This certification is important to ensure third-party monitoring is consistently conducted with an adequate level of quality assurance and control. We appreciate the demonstration for third-party notifiers as outlined in the preamble (87 FR 74750), but do not believe the requirements as proposed in §60.5371b(a) provide enough stringency. Considering the requirements EPA has established for an operator, the same level of scrutiny should also be expected of the third-party data provider when using the same technology. Strict criteria should be established covering the following:

- An expectation from EPA that third parties and their approved detection technologies must be re-certified on a specified frequency. This certification process should be similar to other EPA certifying programs (e.g., EPA auditor).

- An expectation for third parties to attend EPA-specific training, including the do's/don'ts as well as what they are authorized to do or not do – including the handling of data they plan to use within the program.

- Clear criteria for what type of actions may immediately make data collected invalid and/or fully revoke a third party's participation in the program. Regarding EPA's proposed revocation of third party certification (87 FR 74750), we recommend that the criteria for revocation explicitly state that upon a third party's third submission of verifiably false data from any combination of operators or sites, or upon trespass or otherwise unlawful or unauthorized entry to a facility, or vandalizing energy infrastructure, or upon unauthorized distribution or publication of data gathered under the program, the offending third party shall have their certification revoked for a period of no less than three years. Any data gathered at the time of a trespass would render that data invalid.

1.1.2 The super emitter response program must have a transparent and formal notification process where EPA manages the flow of information from the third-party to the operator.

As similarly done with other EPA programs, formal notification to facility owners/operators (and even with the third-party) could potentially be via email or a central online-based system.[8] The process should allow EPA to confirm that the correct operator received the notification and follow-up if the operator does not respond within a certain timeframe. There are also concerns with measurement of emission events, including pin-pointing sources or facilities correctly (especially when there are adjacent facilities in proximity to each other or sharing boundaries), and in conjunction with the minimum resolution of the monitoring technologies.

Some additional considerations include the following:

- **Operators should be given advanced notice of planned third-party activity. As proposed, the response burden for operators is not predictable and operators are unable to properly plan and schedule resources.** If timing and location of surveys are unknown to a facility owner/operator, operators will have no indication of when and how much resources to have available. This is important to promptly evaluate data and implement corrective action if necessary. Third parties may employ technologies, like aerial surveys which can result in multiple detections in a short amount of time. It's not unreasonable to expect that surveys may be conducted by multiple third parties simultaneously or in series, and conversely, there could be extended periods of no third-party activity. Program requirements must balance the needs of operators to plan for both day-to-day operations and promptly prepare for and respond to third-party activity.

- **Detections of potential super-emitter emission events should be shared with the operator within a certain time period from detection to allow for effective and prompt response to reduce the emission impact.** As proposed, third parties only have to provide data "*as soon as practicable to the owner or operator*" under §60.5371b(b)(7). Since there could be many days between when monitoring occurred and when an operator receives the survey data, an investigative analysis may not find any significant ongoing / persistent emissions event. Furthermore, third-party notifiers could attempt to overwhelm a single operator with a rush of data from multiple monitoring campaigns (e.g., using remote-sensing equipment on aircraft) that would be untenable to fully investigate.

We propose suggested timing for these notifications in Comment 1.1.

1.1.3 Monitoring conducted by a third-party should be pre-approved and accepted by EPA prior to execution of the data gathering event.

There are clear protocols, including monitoring plans, that operators are required to have in place to conduct emission monitoring data. Any certified third party that conducts monitoring must be held to the same stringency

[8] If an online-based system is chosen, there will be an additional resource / cost burden on EPA to develop and maintain the functionality of the system. Also, there may be an issue when operators are in close proximity to each other and have shared property boundaries, or when a facility was owned by a specific operator at one time but has been sold to another owner.

as an operator if they were to use the same technology. This reciprocity is important to ensure third-party monitoring is consistently conducted with an adequate level of quality assurance and control. It also is necessary, given that third-party monitoring would create enforceable legal obligations for affected/designated facilities as currently proposed. There is nothing under the law that, in and of itself, prevents any third party from conducting remote monitoring (as noted elsewhere, the law may impose restrictions on where/when/how such monitoring may be done; for example, third-party monitors may not trespass on private property). But when such monitoring has regulatory consequences, it would be arbitrary and fundamentally inconsistent for EPA to set more lenient criteria on third-party monitors than it does for similar monitoring required to be conducted by affected/designated facilities.

At least 30 business days in advance of the planned monitoring campaign, the third-party must submit a monitoring plan to the EPA for approval. The monitoring plan submittal should include the following information (at a minimum):

- Site coordinates and/or map of the area to be monitored;
- Description of monitoring equipment to be used to conduct the activity;
- Documentation of emissions detection limit;
- Proposed starting date and duration of the monitoring activity;
- Contact details (e.g., name, phone number, title) of third-party contact person;
- Name and details of owner of remote monitoring equipment;
- Quality assurance / quality control plan, including calibration procedures, if applicable to the technology (Subsequently, the third-party should also have to demonstrate how it met its monitoring plan for each monitoring event when monitored data is submitted to EPA);
- Specification on how the data will be provided and in what timeframe to the EPA; and
- Certification statement signed by an authorized company official attesting that the third-party will conduct monitoring activities in accordance with EPA requirements.

With the 30-day approval period, it would also allow EPA sufficient time to provide affected facility owners / operators notice of the upcoming monitoring event, which should be provided at a minimum 7 business days prior to the start of the monitoring field event.

1.1.4 There are safety and security concerns with third parties trespassing on private property.

Even though EPA notes in Section IV.C.2.a of the preamble (87 FR 74749) that it considered concerns for the safety of individuals engaged in third-party monitoring and of facility operator personnel, there are still tangible safety concerns related to the use of certain monitoring technology by third parties (e.g., mobile monitoring platforms) to identify super-emitter emissions events. Some operators have experienced public individuals driving through operator sites (especially in remote locations with no “fencing”) with vehicle mounted monitoring devices, which is especially problematic as access can typically be obtained by road, some of which may be private roads. There have also been issues acknowledged between private third-party landowners and trespassers, which can be another point of contention.

Personnel working at our facilities are required to undergo numerous hours of training to safely perform their work duties, including but not limited to wearing the correct personal protective equipment based on site conditions, exposure to extreme heat or cold weather, biologic hazards such as snakes or other critters, specific training on how to navigate rotating equipment, and where and how to identify hazardous chemicals/gas. For example, training specific to the presence of hydrogen sulfide (H_2S) includes hazards, symptoms of exposure, detection devices, and how to safely walk away from exposure.

Individuals require site specific training to be present at any given facility and there is potential liability (to both the individuals and to company assets) for individuals who do not have this training. The proposed SERP framework is geared to remote technologies, which by their nature should in no way necessitate third-party representatives to appear at facilities. API recommends that any information that is collected by a third party that is outside of an EPA-approved monitoring campaign, where EPA and/or operators have not been notified in advance of the data gathering campaign, be considered invalid. As we also provided in Comment 1.1.1 , trespassing (such as driving through a site) should immediately result in revocation of a third party's certification and render any information gathered at the time invalid.

1.1.5 The EPA should clearly manage how third-party monitored data is published in conjunction with corrective actions taken by operators.

Participation in the regulatory process through the super-emitter response program by EPA-certified third parties must include limitations on the ability of those third parties to use the information gathered under the program for any other purpose. Such limitations must include requirements that the third party (and the monitoring companies they contract) maintain the security and confidentiality of data collected during SERP monitoring, where the monitoring results cannot be independently published (via website or social media). EPA has a fundamental role to play in the validation of third party collected data, which extends to the publication of such data. When a third party accepts the responsibility of participating as a certified notifier, they accept this role and handling of data.

- **Monitored data should not be published without context from operator feedback or corrective actions.** EPA's state within the preamble (87 FR 74750) "*owners and operators would have the opportunity to rebut any information in a notification provided by the qualified third parties in their written report to the EPA, by explaining, where appropriate, that (a) there was a demonstrable error in the third party notification; (b) the emissions event did not occur at a regulated facility; or (c) the emissions event was not the result of malfunctions or abnormal operation that could be mitigated."* While we agree with this concept, the proposed framework does not provide the same level of assurance that these rebuttal statements would be linked to the third-party monitored data directly in the public forum without EPA intervention. If the data is posted on other public websites, there is a chance any resolution/follow up comments and descriptions from operators will not be carried over to the non-EPA sites, therefore resulting in inaccurate presentation of the facts. While we concur that data transparency is valuable, and share the goal of disseminating information to mitigate emissions events, these goals must be balanced with adequate considerations for national security risks, reputational risks (e.g., incorrect operator maligned in media, third party is not approved or certified by EPA, permitted events are taken out of context, etc.), and stakeholder risks.

- **EPA should establish a protocol or annual publication updating on progress of the program.** We believe the current language proposed in §60.5371b(e)(4) establishing a new EPA website is extremely flawed and ambiguous. Third-party monitored data on its own will provide very limited context for the general public and can be easily taken out of context. We believe a synthesized annual report or fact sheet published by EPA would offer a clearer depiction of relevant details with full context around super emitters including but not limited to: how many third-party monitoring events took place, the number and location of valid super emitter emission events that were detected, the number of super emitter events that were permitted or authorized emissions, the rate of erroneous notifications and the types of corrective actions that were taken to repair other super emitter emissions identified. Operator related information could remain anonymous in this annual report, unless EPA found specific operators to be conducting insufficient corrective actions or operators that do not acknowledge EPA's notification attempts regarding the monitoring campaigns (and EPA has verified the correct operator and contact information).

  At a minimum, EPA should limit the information for super-emitter emissions events so that the information cannot be misconstrued or used to publicly attack operators in the media; especially operators who are proactive participants within the SERP. The shared goal of finding these leaks and fixing them as expeditiously as possible should remain at the forefront and in conjunction with transparency objectives.

1.1.6 An "investigative" analysis should be conducted in conjunction with initial corrective actions.

As we explain further in Comment 3.2, the EPA outlines in §60.5371b(c) specific actions to take place if a super-emitter emission event occurs. API supports investigating the source and cause(s) of significant emissions events that are brought to an operator's attention Through the process described in our comments. We agree that EPA's investigative actions listed §60.5371b(c) are appropriate and practicable as far as investigating and conducting initial corrective actions for super emitter events. However, EPA's use of the term "root cause analysis" is problematic and ambiguous. The concept of "root cause analysis" is embedded in numerous other regulatory and non-regulatory programs and has varied meaning and purpose in each application. Thus, use of that term here does not clearly and adequately define the scope of the legal obligation, which will make it difficult for operators to understand what must be done to comply and will invite dispute and controversy if/when this program is implemented. To address this concern, we recommend the actions EPA has outlined be maintained, but the term supplied as the definition for those actions be changed to "investigative analysis" as it relates to super-emitters in §60.5371b(c).

1.1.7 After an investigative analysis has occurred, an operator should have the ability to designate the emission event as "no action required," as applicable.

Since the source of an emission detection during a monitoring campaign could be the result of various situations (and even EPA acknowledges that there may be demonstrable errored data), API suggests that the EPA include a pathway for operators to simply identify situations where "no corrective action required" beyond what has been proposed in §60.5371b(e)(1). These additional situations could include 1) the wrong operator was notified; 2) where the emission event cannot be validated by the operator; 3) there was a demonstrable error in the third-party notification; (4) the emission event did not occur at a regulated facility (e.g., well site or compressor station); or 5) the emission event was authorized as authorized or permitted operations. The information an operator should submit back to EPA should be simplified for planned or authorized emissions. Further, within

§60.5371b(e)(1)(iii), EPA must clarify that the applicable standard is limited to the applicable standard of this subpart.

1.1.8 Safe Harbor for Operators

The presence of a super emitter emission event does not necessarily indicate a standard has been exceeded or that a violation has occurred. Moreover, any documents shared with EPA articulating corrective actions taken should be subject to a safe harbor provision that prevents EPA or any other entity from using the information in the document for purposes of enforcement / notice of violation (NOV), civil suit, etc.

1.1.9 The role of states as a delegated authority within the super emitter proposed framework is unclear.

Throughout the preamble EPA uses language that mentions state agencies as delegated authorities. One such example is found at 87 FR 74750, *"The EPA further proposes that the entity making the report shall provide a complete copy to the EPA and to any delegated state authority (including states implementing a state plan) at an address those agencies shall specify."* The role of state agencies within the SERP must be more adequately defined. For example, as explained in these comments, the SERP program is not lawful or practically workable unless EPA takes a direct role in implementing the program (e.g., EPA must review and approve site-specific third-party monitoring plans, EPA must receive and vet the results of third-party monitoring and must decide whether the results are actionable). In the final rule, EPA must explain the process and degree to which these functions may reasonably be delegated to the states and, for functions that EPA determines are delegable, provide mechanisms to assure consistency among EPA's and the delegated states' programs.

2.0 Fugitive Emissions at Well Sites, Central Production Facilities and Compressor Stations

API supports the retention of NSPS OOOOa requirements for optical gas imaging (OGI) monitoring at well sites, central production facilities, and compressor stations. Except for multi-wellhead only well sites (see Comment 2.1), API also supports the proposed audio, visual, and olfactory (AVO) and OGI monitoring frequencies. In addition to the following comments concerning requirements for fugitive emissions at well sites, central production facilities, and compressor stations, API notes that EPA is not providing a meaningful opportunity to comment on a key basis for removing the wellhead only exemption because the underlying data for the Department of Energy (DOE) study[9] is unavailable.

2.1 API proposes AVO inspections only for all wellhead only sites.

EPA's focus on finding large fugitive emissions at single wellhead only sites using AVO inspections is appropriate and should also apply to multi-wellhead only sites. An AVO inspection is the most appropriate tool to rapidly identify large emissions at wellhead only sites. As EPA has already concluded, AVO inspections are a useful tool at

[9] Bowers, Richard L. Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells. United States. https://doi.org/10.2172/1865859

sites that lack extensive background noise and have field gas containing mixtures of methane and VOCs and condensate or produced liquids (87 FR 74727)[10]. Not only do wellhead only sites match these criteria, but their emission points are closer to ground level compared to other sites. For these reasons, out of all well site configurations, AVO is expected to perform the best at wellhead only sites, and it generally can be applied more frequently than other leak detection methods. EPA appropriately concluded that *"the types of emissions sources located at the wellhead, including these large emissions sources found in the U.S. DOE marginal well study, can be easily identified using AVO inspection"* (87 FR 74729)[11]. Given the large number of wellhead only sites and EPA's focus in regulating fugitive emissions at these sites, quarterly AVO inspections are appropriate to detect fugitive emissions at any wellhead only site including single wellhead or multi-wellhead well sites.

The proposed leak detection method and frequency for any emission source should take into consideration the count and relative magnitude of emissions, among other factors. The number of wellhead only sites across the U.S. is estimated to be in the tens of thousands. The resource demand from any leak detection requirement on wellhead only sites using OGI or Method 21 quickly multiplies.

EPA notes that the DOE study "*demonstrates that fugitive emissions do occur from wellheads, and in some cases can be significant"* as the basis for regulating wellheads. Similarly, commenters indicated "the wellhead itself is a source of emissions" because "these well sites have other smaller equipment that leaks and malfunctions, with large emissions having been observed from these sites". While wellheads are a source of emissions, various studies indicate wellhead emissions amount to a very small share of overall well site emissions. A study conducted over the Permian Basin determined that simple sites, such as wellhead only sites, experience median emission rates two orders of magnitude smaller than complex sites (0.03 kg/hr for simple sites vs 2.6 kg/hr for complex sites)[12]. CAMS contracted with Bridger Photonics to conduct aerial surveys performed in the Permian Basin (5,361 pieces of equipment on 1,450 facilities over 250 square miles). The project found that 2% of total detected emissions were from wells and 5% of total detections were from wells[13].

These studies demonstrate that the population average emissions from wellheads is not relatively significant and therefore chasing fugitive leaks from these sources will not be impactful compared to deploying resources to other contributing sources. Nevertheless, we recognize this does not preclude the potential for fugitive emissions from an individual wellhead. Given wellhead only sites number in the tens of thousands, the prudent and most efficient use of resources is to focus on detecting the rare occurrence of large fugitive emissions from wellheads, which can be accomplished with AVO inspections. Coupled with proposed requirements[14] for conversion to non-emitting pneumatic controllers at existing sites, the increased cost of additional OGI screening at these sites raises further concerns regarding premature shut-in of production and states' ability to preserve the remaining useful life of facilities.

[10] On the other hand, AVO inspections are a useful tool for identifying when there are indications of a potential leak without the need for expensive equipment or specialized training of operators. For example, at sites that lack extensive background noise, a person would be able to hear if a high-pressure leak is present, which could present as a hissing sound. Field gas produced at well sites contains a mixture of methane and various VOCs, which have the potential to be detected by smell. Where the field gas contains a lot of condensate or other produced liquids, any resulting leaks would present as indications of liquids dripping or potentially puddles forming on the ground.

[11] The types of emissions sources located at the wellhead, including these large emissions sources found in the U.S. DOE marginal well study, can be easily identified using AVO inspections and would not require the use of OGI for identification. Therefore, the EPA evaluated a periodic AVO inspection and repair program for addressing fugitive emissions from single wellhead only well sites.

[12] Robertson, Anna M., 2020, New Mexico Permian Basin Measured Well Pad Methane Emissions Are a Factor of 5–9 Times Higher Than U.S. EPA Estimates, Environmental Science and Technology, 54(21), 13926-13934 https://pubs.acs.org/doi/10.1021/acs.est.0c02927

[13] https://methanecollaboratory.com/wp-content/uploads/2021/08/Scientific-Insights-Aerial-Survey-in-Permian-August2021_vFinal.pdf

[14] See Comment 7.0

EPA's basis for applying OGI to multi-wellhead only sites is centered around additional connection points and valves with generally smaller emissions (87 FR 74732)[15]. While this basis is true, the focus appears to be misguided. If the principal concern with a single wellhead only site is to find the rare, but possible, large emissions leak, then it should follow that the principal concern for a multi-wellhead only sites should also be the rare occurrence of large emission leaks because it is relatively more likely with more than one well-head. That is, what warrants more attention to a multi-wellhead only site should not be the potential for more small emission leaks, but the greater potential for a large emission leak. Any significant difference in emissions leak potential from a single wellhead only site versus a multi-wellhead only site is not likely to be because of a small emission leak.

More frequent monitoring may also be challenging since many existing wellhead only sites can only be reached on foot due to remote location and lack of lease road access. While we believe quarterly AVO is the appropriate frequency for all wellhead only sites, at a minimum, bimonthly AVO inspections only would also be acceptable as the monitoring requirement for multi-wellhead only sites.

2.2 The proposed definition of fugitive emissions component requires further clarification.

Several aspects of EPA's proposed definition of fugitive emissions component require further clarification.

- **In yard piping should not be included in the definition of fugitive emissions component.** The inclusion of in yard piping as a fugitive emissions component expands that definition in unprecedented ways. Cracks or holes in piping have never been considered fugitive components in any other rule for Leak Detection and Repair (LDAR) in any industry sector by the agency. These types of events represent potential loss of containment and are already repaired or corrected per industry practice and code.[16]
- **Definition should include thief hatches or other openings on a controlled storage vessel only.** Monitoring thief hatches and other openings on uncontrolled storage vessels adds no environmental benefit since the storage vessel emissions will be the same whether they are emitted from the tank vent or through thief hatches or other openings. Combined with the next item, fugitive emissions component should include thief hatches or other openings on a controlled storage vessel that is not subject to NSPS OOOO, OOOOa, or OOOOb because of a construction/reconstruction/modification date on or before August 23, 2011, or a legally and practicably enforceable limit.
- **Definition should also include the appropriate references to NSPS OOOO and OOOOa.** As proposed, fugitive emission components include covers and closed vent systems and openings on storage vessels not subject to NSPS OOOOb requirements. Since EG OOOOc will be implemented over the coming years, the definition of fugitive emissions component should also include the appropriate reference to

[15] Multi-wellhead only well sites. For wellhead only well sites with two or more wellheads, the EPA anticipates that the same large emissions source (i.e., surface casing valves) would be present. In addition to these valves on the wellheads have additional piping, and thus connection points and valves that also present a potential source of fugitive emissions. Emissions from these types of components are generally smaller, and not easily identifiable using AVO.

[16] We note that EPA's rationale for adding yard piping to the definition of "fugitive emissions component" is that, "[w]hile not common, pipes can experience cracks or holes, which can lead to fugitive emissions." 87 Fed. Reg. at 74723. EPA explains that its proposal will "ensure that when fugitive emissions are found from the pipe itself that necessary repairs are completed accordingly." Id. EPA's proposal is vague and fails to provide an adequate opportunity to formulate meaningful comments because EPA does not explain how leak detection should be accomplished for "yard piping" as compared to other already-listed fugitive emissions components, where there are identifiable leak points (such as valve stems or flange interfaces) that are the target of monitoring. For example Section 8.3 of Method 21 (which applies to LDAR standards such as the one here that specify a concentration-based leak definition) explains that monitoring should be conducted "at the surface of the component interface where leakage could occur." Section 8.3 also includes detailed instructions for individual components (such as valves), where particular leak points are identified. In contract, there is no identifiable leak point for "yard piping" that reasonably would be the target of monitoring. In fact, using Method 21, there is no obvious way that the required monitoring could be conducted because of the expansive lengths of pipe where the sort of leaks that EPA seems to be concerned about might occur. Before finalizing a requirement to include yard piping in the definition of fugitive leak component, EPA must provide additional explanation of how the LDAR provisions would apply and provide an opportunity for public comment on that necessarily more specific proposal.

NSPS OOOO and OOOOa requirements. For that time period, a site could have storage vessels subject to NSPS OOOO or OOOOa and be subject to NSPS OOOOb fugitive monitoring. See Comment 12.5 regarding the proposed reconciliation of NSPS OOOO and OOOOa with NSPS OOOOb and EG OOOOc.

- **Existing clarifying language from NSPS OOOOa should be retained.** Since NSPS OOOOb proposes to allow natural gas-driven pneumatic controllers and pumps in limited circumstances (e.g., sites in Alaska without access to electric power), the existing language from the NSPS OOOOa definition should be retained to clarify what is considered fugitive emissions.

Based on the above clarifications, API offers the following suggested redline, which retains much of the current NSPS OOOOa definition, to the proposed definition of fugitive emissions component in NSPS OOOOb and EG OOOOc:

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

2.3 Delay of repair requirements should be expanded.

Due to the hundreds of thousands of sites that would be subject to fugitive monitoring under NSPS OOOOb and EG OOOOc, EPA should expand the proposed delay of repair requirements in the following ways:

- **Consistent with the requirements for natural gas processing plants, EPA should allow for delay of repair due to parts unavailability.** NSPS VVa, incorporated by reference in NSPS OOOO and OOOOa for gas plants, allows for delay of repair beyond a unit shutdown if "*valve assembly supplies have been depleted, and valve assembly supplies had been sufficiently stocked before the supplies were depleted.*"[17] In the Preamble to the November 2021 Proposal[18], EPA recognized that operators of older equipment may experience delays in obtaining replacement parts. Given current supply chain issues and the larger number of well sites, centralized production facilities, and compressor stations, EPA should expand the current delay of repair requirements to include delays because of parts unavailability.
- **EPA should add other potential circumstances beyond an operator's control that would require a delay of repair.** Repairs may be delayed due to circumstances not currently listed in the rule. Specifically, there are seasonal constraints related to farming and/or endangered species where operators cannot bring a rig in or have surface disturbance. Delay of repair should be allowed for these unique situations.

Based on these items, API offers the following suggested redlines to §60.5397b(h)(3), which are based on existing regulatory language from NSPS VVa:

[17] 40 CFR §60.482-9a(e)
[18] 86 FR 63174

(3) *Delay of repair will be allowed:*

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

(ii) *If the necessary replacement part supplies have depleted and supplies had been sufficiently stocked before supplies were depleted, the repair must be completed as soon practicable, but no later than 30 days once the necessary replacement part supplies are available; or*

(iii) *If the necessary repair equipment cannot be brought to the site for reasons, such as lease restrictions for farming or seasons for endangered species, the repair must be completed as soon practicable, but no later than 30 days once repair equipment may be brought to the site.*

2.4 Repair timelines should be consistent for leaks identified using AVO or OGI.

The repair timelines should be the same whether the fugitive emissions at well sites, centralized production facilities, and compressor stations are identified using AVO, OGI, or Method 21 because the necessary repair actions are agnostic to the detection method. In other words, operators should have the same time to make repairs regardless of leak detection method because the repair actions depend more on the leaking component rather than detection method.

EPA's stated reason for requiring shorter repair timelines is *"so that the monthly AVO inspections do not overlap the repair schedule"*[19]*.* This justification is insufficient for two reasons:

- As proposed, monthly AVO inspections would apply only to compressor stations. This overlap would not occur for bimonthly or quarterly AVO inspections at well sites and centralized production facilities.
- EPA has allowed repair timelines to overlap with inspection in other regulations. Under existing LDAR regulations, a component may be on delay of repair for multiple monitoring periods in certain circumstances.

While AVO is generally more effective at detecting larger emissions, the existing OGI repair timelines do not consider emission rate because OGI cannot quantify the leak rate. The same inability to quantify fugitive emissions also applies to AVO, and so EPA should have the same repair timelines for both detection methods. Finally, consistent timelines would also streamline compliance.

To address this concern, API offers the following suggested redline of §60.5397b(h):

[19] 87 FR 74737

Each identified source of fugitive emissions shall be repaired in accordance with paragraphs (h)(1) and (2) of this section.

(1) A first attempt at repair shall be made ~~in accordance with paragraphs (h)(1)(i) and (ii) of this section.~~

~~(i) A first attempt at repair shall be made no later than 15 calendar days after detection of fugitive emissions that were identified using visual, audible, or olfactory inspection.~~

~~(ii) If you are complying with paragraph (g)(1)(i) through (iv) of this section, a first attempt at repair shall be made~~ no later than 30 calendar days after detection of the fugitive emissions.

(2) Repair shall be completed as soon as practicable, but no later than ~~15 calendar days after the first attempt at repair as required in paragraph (h)(1)(i) of this section, and~~ 30 calendar days after the first attempt at repair ~~as required in paragraph (h)(1)(ii) of this section~~.

2.5 EPA should clarify depressurized equipment are exempt from fugitive emissions monitoring.

State rules, including New Mexico[20] and Colorado[21], exempt depressurized equipment[22] from fugitive emissions monitoring because leak surveys are not anticipated to result in emissions reductions at these facilities. Monitoring would resume once the site or equipment is back in service. EPA should provide a clear exclusion for these types of facilities or equipment under both NSPS OOOOb and EG OOOOc. One suggestion would be to model the regulatory language on the existing storage vessel out of service and return service requirements.

See also Comment 13.3.

2.6 Additional clarification is needed for the proposed definition of modification for a centralized production facility.

EPA's proposed definition of modification for the collection of fugitive emissions components at a centralized production facility presents a challenge since the operator of a centralized production facility may not know when an action occurs at an offsite well that would trigger modification at the centralized production facility especially when the operator differs between the centralized production facility and the offsite wells that send production to it. The operator of the centralized production facility may not know when an action occurs at an offsite well that would trigger modification at the centralized production facility since the upstream operator is typically only required to notify the centralized production facility operator when a new well is drilled and starts to send production to the gathering system. The upstream operator may not necessarily identify the specific centralized production facility. EPA may not have anticipated this scenario in proposing the definition of modification for the collection of fugitive emissions components at a centralized production facility.

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[20] 20.2.50.116.C(9) NMAC
[21] https://drive.google.com/file/d/1a3IJ74txUxJ241wgh-ZMRx0Rn7LV3z2V/view
[22] The CO regulations reference depressurized equipment, while the NM regulation references temporarily abandoned wells.

To address this concern, API suggests that the modification criteria for centralized production facilities be limited to "An increase in design throughput capacity occurs with the addition of a storage vessel at an existing centralized production facility". This criterion is simple, clear, and aligned with the purpose and definition of a centralized production facility, which is to gather hydrocarbon liquid production into storage vessels. As such, API offers the following suggested redline of §60.5365b(i)(2):

For purposes of §60.5397b and §60.5398b, a "modification" to centralized production facility occurs when~~:~~ an increase in design throughput capacity occurs with the addition of a storage vessel at an existing centralized production facility.

~~*(i) Any of the actions in paragraphs (i)(1)(i) through (iii) of this section occurs at an existing centralized production facility;*~~

~~*(ii) A well sending production to an existing centralized production facility is modified, as defined in paragraphs (i)(1)(i) through (iii) of this section; or*~~

~~*(iii) A well site subject to the requirements of §60.5397b or §60.5398b removes all major production and processing equipment, such that it becomes a wellhead only well site and sends production to an existing centralized production facility.*~~

We also suggest EPA add clarification to the definition for central production facility that addresses custody transfer.

2.7 EPA's proposed well closure plan requirements present several technical and legal issues.

After reviewing EPA's proposed well closure plan requirements, API has identified the following technical and legal issues:

- **The proposed well closure plan requirements are duplicative with other regulations.** Well closure requirements are within the jurisdiction of State Oil & Gas Commissions and other agencies, not the EPA. Under state law, a well is required to be plugged and abandoned when it has reached the end of its useful life. In all States, operators must provide written notice of plugging and comply with regulatory requirements to plug and abandon the well, including removing equipment, setting downhole plugs, cementing in the casing, capping the well to prevent fluid migration and restoring the surface site. These practices are done to permanently confine oil, gas and water into the strata in which they were originally found. For wells located on federal lands, separate BLM requirements also apply for well closure. Depending on the well location (e.g., located in an area with potash mining), additional requirements may also apply. For some wells, EPA would be adding a fourth set of well closure requirements.

  Therefore, EPA's proposed notifications and well closure plan requirements are duplicative, unnecessary, and increase administrative burden while providing no discernible accompanying environmental benefit when an operator is working to properly close a well. In certain cases when an emergency plugging is required, the proposed notification timelines may be impossible to meet.

- **EPA does not have the technical expertise to review well closure plans.** State Oil & Gas Commissions have the technical knowledge to evaluate well closure plans, because they have the jurisdiction for well closure. Without the technical knowledge, EPA's proposed well closure plan requirements require significant operator and agency resources but provide no additional environmental benefit. Operators should only be required to maintain records of an approved well closure plan by the state authority with jurisdiction; these records could be provided to EPA upon request.

Under existing State and BLM requirements, well closure plans include detailed information on the well casing, tubing, and rod dimensions, perforation depths, proposed plug materials, depths, tagging, and verification, leak testing for cast iron bridge plug (CIBP), and other required data.

- **EPA does not have authority under CAA § 111 to impose financial assurance requirements.** Part of the proposed well closure plan is a "description of the financial requirements and disclosure of financial assurance to complete closure". This requirement is clearly beyond EPA's authority under the Clean Air Act (CAA). For more details, refer to Comment 12.8.

- **The proposed requirements may create unforeseen liability consequences.** EPA has not clarified how the proposed well closure requirements will transfer with ownership. Under State and BLM rules, chain of title is defined. EPA should not create duplicative requirements that could create potential liability consequences for operators.

- **The notification prior to well closure should be removed. If EPA finalizes the proposed well closure requirements, EPA must clarify when a well closure plan is required to be submitted.** Language at §60.5397b(l) potentially conflicts with §60.5420b(a)(4) in terms of whether a well closure plan needs to be submitted every time that production ceases for more 30 days or only when the operator intends to close the well and stop fugitive emission monitoring. "Cessation of production" is not defined in the proposed regulations. A 30-day period from cessation of production is not indicative of well closure. Operators may have many instances where wells are shut-in for periods of 30 days or more, with complete intent to return the wells to production. A few examples include a facility undergoing maintenance or repair, shut-in for offset fracturing, lack of access to gathering, or wells on cycled production. We request EPA clarify that the well closure plan requirements and notification only when operators intend to permanently close the well and stop fugitive monitoring.

Overall, API recommends that requirements within NSPS OOOOb and EG OOOOc pertaining to well closure be limited to the following:

- **A recordkeeping requirement to maintain records of an approved well closure plan by the local authority with jurisdiction.** This recordkeeping only requirement would avoid unnecessary and duplicative requirements with State Oil and Gas Commissions. The records could be submitted to EPA upon request.

- **A final OGI survey to confirm no detected fugitive emissions after well closure.** EPA could still require a final OGI survey after well closure.

3.0 Alternative Leak Detection Technologies including Periodic Screening and Continuous Monitoring

API recognizes and appreciates EPA's initial and important efforts in creating a framework for alternative leak detection technologies, including continuous monitoring, in NSPS OOOOb and EG OOOOc. However, we urge EPA to make key adjustments in the final rules to enhance the use of these technologies and to not unintentionally disincentivize development and deployment of these technologies. Making alternative technologies more accessible in these rules can also have synergistic benefits with measurement-informed inventory goals in related rulemaking such as the Inflation Reduction Act's Methane Emissions Reduction Program and EPA's Greenhouse Gas Reporting Program.

These adjustments are described in our comments below, including initial comments on EPA's FEAST modeling. While API is exploring additional modeling analyses, due to the short comment period, any additional modeling analysis may be provided in a subsequent submittal. We welcome the opportunity for future discussions on this important topic with EPA staff.

3.1 Comments Regarding Both Periodic Screening and Continuous Monitoring Technologies

3.1.1 Technologies should be available for use upon finalization of NSPS OOOOb and EG OOOOc.

To facilitate adoption of alternative leak detection technologies, operators need options available beginning with finalization of the proposed rules. EPA's proposed 270-day review timeline means that technologies would likely not be approved until after the first AVO, OGI, or Method 21 inspection, since the initial inspection would be required 90 days after NSPS OOOOb is finalized. This gap may disincentive the use of alternative technologies as operators would already be required to implement the standard fugitive emissions monitoring program with AVO, OGI, and/or Method 21 inspections.

Recognizing that EPA is unable to approve technologies until the rules are finalized, API proposes that alternative technology applications be granted conditional approval if they are submitted within 90 days after the final rule is published in the Federal Register (based on the proposed timelines for the initial AVO, OGI, or Method 21 surveys). This initial conditional approval period would allow for the immediate use of those alternative technologies to achieve initial compliance with NSPS OOOOb. An alternative to initial conditional approval could be extending the deadline for initial monitoring surveys from 90 day to one (1) year in §60.5397b(f) and §60.5398b(b)(2). Time beyond the 270-day conditional approval would be needed for operators to contract with vendors and conduct the initial surveys.

Operators would be able to use the conditionally approved technologies until EPA provides written disapproval to the requestor. Disapproval of a conditionally approved technology should not be considered a deviation for operators that used the technology while it was conditionally approved. Upon disapproval of a conditionally approved technology, operators would be able to comply with AVO, OGI, or Method 21 requirements or use another approved or conditionally approved alternative technology. EPA has already proposed the idea of conditional approval for alternative technologies, so this idea could be extended to allow for technologies to be available for initial compliance. EPA could also utilize technologies approved by a state or another country (e.g., Colorado or Canada) as a starting point for initial conditional approval.

In place of or in addition to initial conditional approval, API recommends that EPA prioritize review of initial alternative technology applications (submitted within 90 days after final rule is published in Federal Register) based on the following criteria:

- The technology is already approved for use by a state or another country. Approval by another agency means that the technology has been reviewed previously and is likely to meet EPA's proposed minimum detection threshold of ≤ 30 kg/hr (based on a probability of detection of 90%) as shown in Table 1 and Table 2 to NSPS OOOOb.

- The technology is already used by one or more operators for monitoring under voluntary efforts or regulatory programs. One potential measure could be the number of sites monitored in 2022 using the alternative technology under voluntary efforts or other regulatory programs.

An initial conditional approval period and prioritization of review would allow for quicker adoption of alternative technologies and would also alleviate pressure from EPA to review a potential influx of applications upon rule finalization. Without these measures, EPA could be overwhelmed with applications, and the full 270-day review period would pass before the first technologies would be conditionally approved.

3.1.2 EPA should clarify how the review and conditional approval process will be implemented.

We request EPA provide the following clarifications regarding the application review and conditional approval process for use of alternate technologies:

- EPA should clarify that operators are able to use conditionally approved technologies until EPA provides written disapproval to the applicant.
- EPA needs to consider how to effectively notify operators when a conditionally approved technology is disapproved.
- EPA should also clarify that disapproval of a conditionally approved technology should not affect compliance for operators that used the technology while it was conditionally approved. Upon disapproval of a conditionally approved technology, operators would be able to comply with AVO, OGI, or Method 21 requirements or use another approved or conditionally approved alternative technology.

EPA should also elaborate on how deficiencies in an application will affect the proposed review timelines. For the initial 90-day review and final 270-day review, the proposed regulatory language implies that deficiencies in an application will result in disapproval and require the applicant to revise its request and restart this process. As with other application processes, agencies will typically issue requests for additional information with appropriate deadlines so that applicants can resolve deficiencies without restarting the entire application process. Forcing applicants to restart the process for any application deficiency would further delay the approval of alternative technologies for use by operators.

3.1.3 Emissions detected from covers and closed vents systems using alternative technology or while doing required follow-up surveys do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented.

As discussed in more detail in Comment 5.1 , emissions detected from covers and closed vent systems are not necessarily violations of the "no identifiable emissions" standard since it is a work practice standard rather than a numerical zero emission standard. As with all other fugitive emissions components, detection of a leak (in this case, defined as identifiable emissions) through alternative technology or a required follow-up survey triggers the obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented. Treating emissions detected from covers and closed vent systems as violations not only fails to acknowledge technical reality contrary to best system of emission reduction (BSER), but it also disincentivizes the use of alternative technology.

3.1.4 While API appreciates EPA providing modeling, EPA's current model overestimates the effectiveness of AVO and OGI.

We appreciate EPA's efforts to create a technology-agnostic, performance-based alternative test method framework supported by an underlying, publicly available FEAST model. In EPA's model, the probability of detection curves for AVO and OGI have 100% probability of detection for leaks above approximately 200 g/hr and 60 g/hr, respectively. While these are useful detection methods in various applications, these characterizations overestimate their effectiveness in certain field conditions and leads to impractical performance standards for the alternative technologies as discussed further in Comment 3.3.1 for periodic screening and Comment 3.4.5 for continuous monitoring.

For example, AVO inspections are less likely to find large leaks if they are located above the person performing the inspection, they occur in areas that the person cannot enter due to safety concerns (e.g., potential for H_2S exposure), or they are located in areas with high noise among other reasons. While 60 g/hr is the current NSPS OOOOa and proposed NSPS OOOOb and EG OOOOc standard for OGI cameras, probability of detection for OGI also depends on the camera operator and field conditions.[23] A more realistic characterization of AVO and OGI detection methods would create a more realistic equivalency model for alternative technologies. Due to the short comment period, we may continue to analyze EPA's assumptions about intermittency of leaks, model plant configurations (i.e., equipment types and component counts), and leak occurrence in subsequent comments.

3.1.5 The alternative technology framework should allow flexibility in conducting leak surveys due to seasonal challenges.

The alternative technology framework should allow for flexibility in conducting AVO/OGI and screening surveys due to seasonal challenges and weather events. Some examples include but are not limited to:

- Snow cover can adversely affect the ability of some alternative technologies to detect methane during part of the year.
- High winds can also prevent aerial-based technologies from being deployed on certain days.
- Weather events such as hurricanes may limit the ability to deploy OGI camera operators to sites for surveys.

The alternative technology framework should allow different technologies to be deployed at appropriate frequencies throughout the year. The deadline for the next survey would be based on the type of site and the last survey conducted. As an example, at single wellhead only site, an operator could conduct AVO inspections for the first two quarters of the year followed by a screening survey at ≤ 2 kg/hr and then another AVO inspection no later than four months after the screening survey, based on EPA's proposed requirements. Flexibility in applying alternate screening technologies should include provisions that use of a different technology than originally

[23] Daniel Zimmerle, Timothy Vaughn, Clay Bell, Kristine Bennett, Parik Deshmukh, and Eben Thoma. *Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions*. Environmental Science & Technology 2020 54 (18), 11506-11514 DOI: 10.1021/acs.est.0c01285

planned (due to weather or other external factors) constitutes an allowance, not a deviation from an operator's monitoring plan.

3.1.6 Framework for alternative leak detection technologies should allow multiple technologies, including satellite, to be combined. More combinations of technologies should be added to the proposed periodic screening matrices.

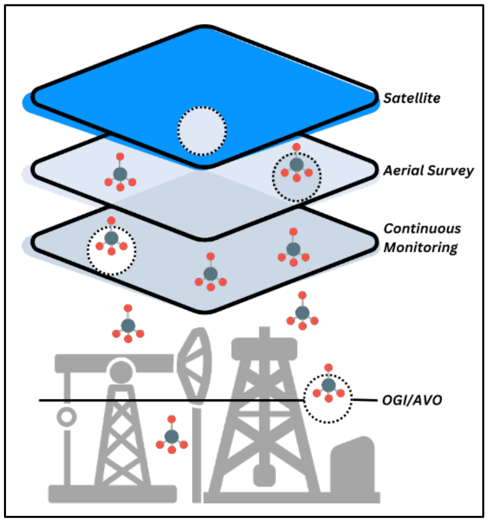
Overall, API believes that allowing the use of a combination of alternative leak detection technologies can be effective to find and fix leaks. This alternative approach recognizes that each leak detection technology (AVO, OGI, Method 21, periodic screening, or continuous monitoring) has strengths and weaknesses in terms of detection threshold, proximity to the source, localization performance, deployment frequency, and costs. For example, ground-based OGI has a low detection threshold and localizes the leak to a particular component but requires proximity to the source and is infeasible to deploy at higher frequencies. Whereas satellites, aerial and continuous technologies can be deployed more frequently than ground-based OGI, the increased distance from the source may not detect leaks on the component level. With these remote detection technologies, resources can be deployed more efficiently to repair leaks – operators would only need to visit sites with detected emissions to make repairs whereas using only OGI surveys require operators to visit each site but could result in no detected emissions. A continuous monitoring system can quickly detect a leak and depending on sensor location, provide an approximate location, but may not fully visualize its location like a plume map from a satellite or aerial survey. In other words, no individual leak detection technology offers a perfect solution.

By allowing the option for a combination of these various technologies into a single monitoring plan or framework, the weaknesses of one technology can be offset by the strengths of another, and the selected technologies work together to improve leak detection and reduce emissions in a flexible and cost-effective manner. Technologies can be combined such that larger emissions are quickly detected, and technologies that detect smaller emissions are deployed less frequently. Finding and fixing the biggest leaks quickly can greatly impact the overall emission reductions.

A multi-layered approach for leak detection combines various technologies to achieve greater emission reductions. Some fugitive emissions may be detected with traditional OGI or AVO during regular LDAR inspections. Intermittent emissions are not always detected during OGI or AVO inspections; however, they may be detected by a continuous monitoring system. Deploying continuous monitors is not an option for all sites, such as those without access to reliable grid power. Alternatively, an aerial survey may detect emissions from such sites over a large area. Although satellites cannot always detect emissions at the component level, they can be useful for basin-wide detection of large emissions that may occur outside of scheduled inspections. This concept of layering various leak detection technologies is illustrated in the graphic below where lines and layers represent strengths of a given technology while the dashed circles represent weaknesses allowing undetected emissions. An example of this multi-layered approach using data from the Permian Basin can be found in an industry pre-publication paper[24].

[24] Cardoso-Saldaña FJ. *Tiered Leak Detection and Repair Programs at Oil and Gas Production Facilities*. ChemRxiv. Cambridge: Cambridge Open Engage; 2022; This content is a preprint and has not been peer-reviewed. DOI: 10.26434/chemrxiv-2022-f7dfv

Figure 1. Multi-layered Approach for Leak Detection



EPA has already included the idea of layering technologies with the screening survey plus annual OGI survey options in the periodic screening matrices. API has two specific suggestions regarding an alternative multi-layered approach for leak detection:

- **API recommends that continuous monitoring (see also Comment 3.4.1) and satellite technology be included as options directly in the matrices in combination with the periodic survey with and without annual OGI.** In other words, combinations like "Quarterly + Weekly Satellite + Annual OGI", "Quarterly + Weekly Satellite", "Quarterly + Continuous + Annual OGI", and "Quarterly + Continuous" should be modeled and added to the periodic screening matrices with appropriate detection thresholds for the screening technology. Satellite technology would be defined with a ≤ 100 kg/hr detection threshold and a weekly frequency. Having frequent satellite surveys will allow reducing the number of periodic surveys per year for a given detection threshold with and without an annual OGI survey.

- **Separately, we would also welcome an additional optional and flexible framework independent from the periodic screening matrices and case-by-case AMEL process where an operator can develop a monitoring plan for each basin/site with their chosen suite of EPA-approved technologies via EPA-approved modeling.** Similar to EPA's proposed clearinghouse approach to approving alternative screening technologies, EPA could evaluate and approve different modeling platforms for use in developing monitoring plans. Modeling could be refined over time based on data generated through the monitoring plan. The initial modeling should represent the highest emissions level since emissions should decrease over time as NSPS OOOOb and EG OOOOc are implemented over the next several years. This approach would both allow the technology to mature over time and a streamlined approach to alternative modeling compared to the existing case-by-case AMEL process.

  This flexible framework gives operators a clear pathway for a custom, fit-for-purpose option and would be an alternative to both the AVO/OGI requirements and alternative technology requirements. To benefit smaller operators, EPA should consider both a conservative, and realistic, default plan that allows for flexibility in monitoring technology as well as an option where an approved monitoring plan can be used by other operators with similar assets.

3.1.7 Repair timelines should be consistent for leaks using AVO/OGI or alternative leak detection technologies.

Recognizing that repair timelines are part of the overall effectiveness of a leak detection program, API recommends that repair timelines be consistent between traditional (AVO, OGI, or Method 21) and alternative (periodic screening or continuous) leak detection programs. Repair actions depend more on the leaking component rather than detection method. The proposed repair or corrective action timelines in §60.5398b(b)(4) for periodic screening and §60.5398b(c)(6) for continuous monitoring are shorter than those in §60.5397b(h) for fugitive emissions components and §60.5416b(b)(4) for covers and closed vent systems. The shorter repair timelines for alternative leak detection technologies may disincentivize their use. Consistent repair or corrective action timelines would streamline compliance and facilitate the use of multiple technologies. If EPA chooses to finalize shorter repair timelines for alternative technology, API recommends that repairs be prioritized based on higher detected emissions.

3.1.8 EPA should allow operators to use alternative technology to comply with NSPS OOOOa without an AMEL.

Since the proposed NSPS OOOOb fugitive monitoring requirements including alternative technology are at least as stringent as the existing NSPS OOOOa requirements, EPA should allow operators use of alternative technology for NSPS OOOOa compliance without going through the Alternative Means of Emission Limitations (AMEL) process or waiting for state plans to be fully implemented under EG OOOOc. Both the AMEL process and EG OOOOc state plan implementation could take years. EPA can make the NSPS OOOOb alternative technology a compliance alternative for NSPS OOOOa since EPA is planning to update certain aspects of NSPS OOOOa in conjunction with this rulemaking. This addition should not require further notice since the requirements are at least as stringent as the existing NSPS OOOOa requirements. Some alternative technology (e.g., aerial surveys) is deployed over a particular basin or portion thereof and could include both NSPS OOOOa and OOOOb sites. Therefore, allowing the use of alternative technologies for NSPS OOOOa compliance without an AMEL would further incentivize the adoption of these emerging technologies.

3.2 The term “investigative analysis” should replace “root cause analysis”.

The specific term “root cause analysis” has other meanings and specific denotations in various regulations and in the oil and gas industry. There is also a legal issue with how this term can be interpreted in any legal or enforcement proceedings, as well as how it could obligate operators to actions or additional requirements that are not necessarily included within this proposed rule.

API understands and supports EPA’s intent for investigating why certain emission events or leaks have occurred, but recommends the removal of the term “root cause analysis” and replacement with the term “investigative analysis” within NSPS OOOOb and EG OOOOc.

We offer additional comments specific to how “root cause analysis” has been proposed with respect to the super-emitter response program in Comment 1.1.6.

3.3 Comments Specific to Periodic Screening Technology

3.3.1 Proposed periodic screening matrices do not incentivize the use of the alternative technology.

While API acknowledges EPA's proposed matrices of minimum detection thresholds and frequencies, they do not incentivize the use of alternative technology as proposed. To have the same monitoring frequency as OGI, alternative technology must have a minimum detection threshold of ≤ 1 kg/hr for both quarterly OGI and semiannual OGI requirements. This proposed performance level effectively limits the alternative technology options as operators are more likely to use technology with the same or less frequent monitoring than OGI. The proposed performance standards in the matrices are more stringent than needed in part because EPA's FEAST model overestimates the effectiveness of AVO and OGI inspections as mentioned previously in Comment 3.1.4. To incentivize the use of alternative technologies, API believes that quarterly screening surveys with an annual OGI survey should equate to a minimum detection threshold of ≤ 10 kg/hr for sites subject to quarterly OGI; the rest of the matrices would be adjusted accordingly. Supporting modeling analysis may be provided in subsequent comments.

These matrices also do not appear to be based primarily on the minimum leak detection threshold. In proposed Table 1 to Subpart OOOOb of Part 60, the minimum detection threshold is proportional to screening frequency between monthly and bimonthly frequencies without annual OGI (i.e., minimum detection threshold is halved for twice as frequent monitoring). However, if an annual OGI survey is included with monthly and bimonthly screening surveys, the minimum detection threshold is decreased by a factor of 3 instead of the expected 2 (i.e., monthly + annual OGI requires 30 kg/hr detection while bimonthly + annual OGI requires 10 kg/hr instead of the expected 20 kg/hr). While frequency and detection threshold are not the only parts of a leak detection program, one would expect frequency and detection thresholds to be roughly proportional assuming that other aspects of the leak detection program (e.g., repair timelines) are constant.

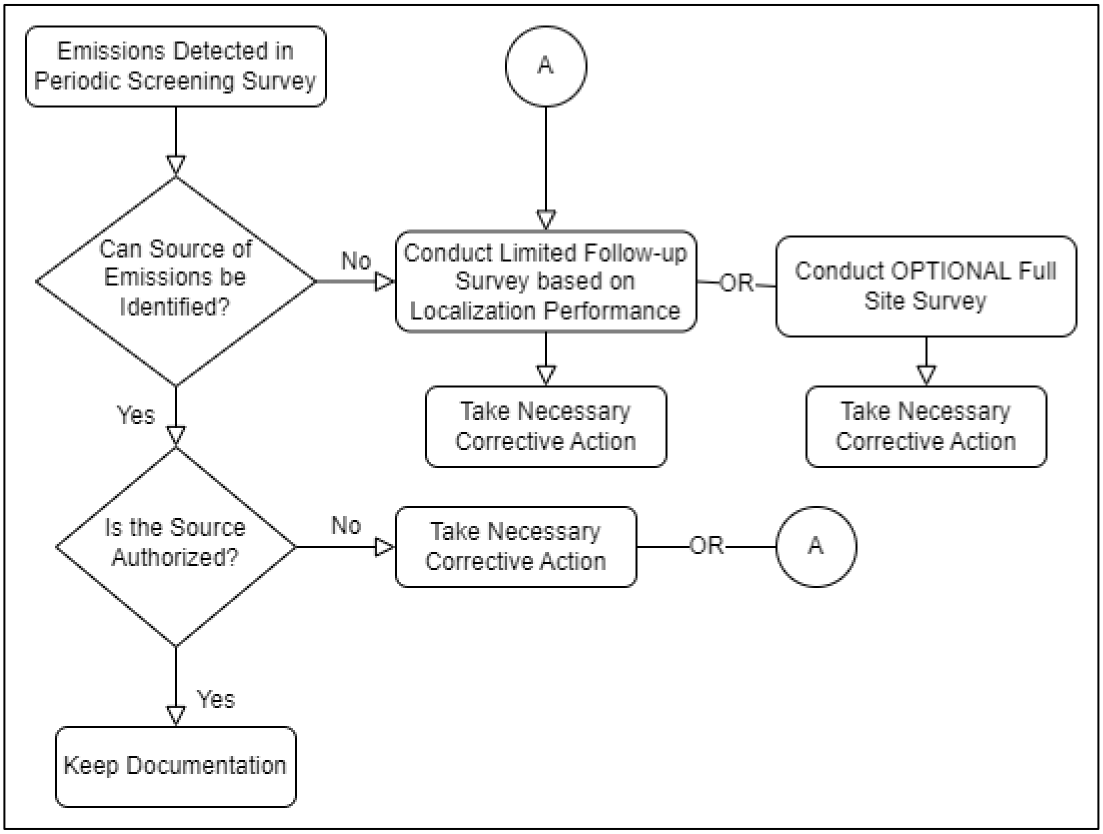
3.3.2 Proposed follow-up actions for periodic screening surveys should be revised.

As discussed in Comment 3.1.7, proposed repair or corrective action requirements for alternative technology should not disincentivize their use. API supports that a full site follow-up OGI survey fulfills the annual OGI survey requirement (where applicable) as indicated in §60.5398b(b)(3)(iii). Regarding the proposed requirements for periodic screening in §60.5398b(b)(4), API offers the following suggestions:

- **The requirements on receiving results of periodic screening and conducting follow-up surveys should be separated from other repair requirements to avoid confusion.** The language in §60.5398b(b)(4) implies that receiving periodic screening results and conducting follow-up surveys are repair requirements when they are both monitoring requirements to detect or confirm leaks.
- **The timeline for receiving results of periodic screening should be extended from 5 calendar days to 5 business days.** Periodic screening surveys can cover hundreds of sites, and so vendors and operators need additional time to process the data for further action.
- **Follow-up surveys and inspections should be limited to sites where the source of emissions cannot be identified based on the localization performance of periodic screening results and other operational information.** Follow-up OGI surveys and cover and closed vent system inspections should not be required if the source of detected emissions can be identified based on the localization performance of the

alternative technology and/or other data. Alternative technology has varying degrees of localization performance in terms of being able to identify emissions on the site-level, equipment group-level, equipment-level, or component-level. Our proposed follow-up action process gives operators the necessary flexibility in responding to detected emissions and is presented in Figure 2and described in detail below.

Figure 2. Flowchart of Proposed Follow-up Actions for Periodic Screening Surveys



When emissions are detected in a periodic screening survey, the operator first tries to identify the source of emissions from the survey results and other available information. For safety and cost reasons, follow-up surveys in the field should be limited to situations where additional information is needed to identify or confirm the source of detected emissions. If the source of detected emissions can be identified, next steps would be based on the type of source.

- If the source of emissions is permitted or otherwise authorized, including maintenance activities, no further action would be required other than to keep documentation. Examples include, but are not limited to, engine or turbine exhaust, uncontrolled storage vessel, planned compressor blowdown, planned engine or turbine startup or shutdown, or properly operating control device. This situation is especially important to compressor stations where periodic surveys are likely to detect emissions from sources operating in compliance with applicable requirements.
- If the source of emissions is a process upset, leak, or other unauthorized release, the operator should be able to directly take necessary corrective actions rather than spending time and effort on a follow-up survey to confirm the source. Taking direct action with the appropriate timelines reduces emissions faster than conducting a follow-up survey first. If the operator determines that a follow-up survey is appropriate to confirm the source of detected emissions, they should be

able to conduct one based on the localization performance of the technology or an optional full site survey.

If the source of detected emissions cannot be identified, operators would conduct a follow-up survey limited to the localization performance of the alternative technology or conduct a full site survey to satisfy the annual OGI survey requirement (if applicable). If two or more full site surveys are conducted within a 12-month period, the most recent full site survey would determine the deadline for the next required annual OGI survey (if applicable). As an example, an alternative technology that can only detect leaks on the site level would require a full site survey while one that can detect leaks down to the equipment would require follow-up surveys only on equipment with detected leaks. Requiring a full site survey anytime that emissions are detected from periodic screening surveys is practically the same monitoring requirement as the primary AVO/OGI requirements but with the additional cost of conducting periodic screening surveys. Due to the large volume of data that can be generated from periodic screening surveys, limited follow-up surveys allow OGI resources to be used in a focused and cost-effective manner. Limited follow-up surveys could also have environmental benefits with reduced vehicle and road dust emissions due to less site visits compared to a full follow-up survey required for every time emissions are detected during a periodic screening survey.

- **Repair timelines should be consistent with AVO/OGI requirements.** Repair timelines should be consistent between traditional and alternative leak detection programs to streamline compliance and facilitate the use of multiple technologies. Therefore, the language in §60.5398b(b)(4)(iii) should simply reference the appropriate repair requirements for fugitive emissions components and covers and closed vent systems.
- **The proposed investigative analysis for control devices in §60.5398b(b)(4)(iv) and covers and closed vent systems in §60.5398b(b)(5) should be initiated within 5 business days.** While API recognizes the importance of proper control device and cover and closed vent system operation, we propose that the investigative analysis be initiated within 5 business days of either receiving the periodic screening survey results in the case that the control device, cover, or closed vent system can be identified as the source of emissions or conducting the limited or full site follow-up survey, whichever is later. This proposed timeline would be consistent with the framework we propose for the SERP in Comment 1.1. EPA's proposed 24-hour timeline is too short to be practical.
- **The proposed investigative analysis for covers and closed vent systems in §60.5398b(b)(5) is more stringent than the repair requirements under §60.5416b(b)(4) and should be removed.** As proposed in §60.5398b(b)(5), a leak or defect in a cover or closed vent system detected by follow-up inspections would require additional analysis beyond repair, including a determination of whether it was operated outside of its design. A leak or defect in a cover or closed vent system detected by routine inspections would be subject only to repair under §60.5416b(b)(4). The investigative analysis for covers and closed vent systems under the alternative technology requirements goes beyond the primary standards, and so §60.5398b(b)(5) should be removed.
- "**Root cause analysis" should be replaced with "investigative analysis".** Consistent with Comment 3.2, the term "investigative analysis" should replace "root cause analysis" in §60.5398b(b)(4)(iv) and §60.5398b(b)(5) (if that requirement remains).

3.4 Comments Specific to Continuous Monitoring Technology

We support EPA's inclusion of continuous monitoring in §60.5398b(c), and our members believe there is great potential in the use of continuous / near-continuous methane monitoring technologies. However, some of the proposed elements are problematic for practical implementation and use of continuous monitors. Therefore, we offer the following comments to craft a more functional continuous monitoring program based on the types of monitors that currently exist, focused on the desired outcome of detecting methane emissions at oil and natural gas production facilities to identify necessary response or repairs, if warranted.

3.4.1 The use of continuous monitoring technology within the periodic screening matrices must be clarified.

The proposed rule language is unclear whether continuous monitoring technology could also be used under the periodic screening survey requirements in §60.5398b(b) and associated matrices. For continuous monitoring technology that simply detects rather than quantifies methane emissions, these technologies could be used for periodic screening surveys. In these situations, the continuous monitor acts like a smoke alarm to notify operators of potential issues. Since continuous monitors can be used more frequently than monthly, EPA should consider adding a more frequent tier or a separate continuous monitoring row to the matrices. The equivalent emission reductions from continuous monitoring could be demonstrated through appropriate modeling. **We recommend incorporating continuous monitoring into the alternative screening matrix for the reasons discussed and to streamline inclusion into the monitoring plan framework we have described in Comment 3.1.6.**

3.4.2 The framework for continuous monitoring should be designed with both fenceline and within-the-fenceline technologies in mind.

As written, EPA's proposed requirements for continuous monitoring appear to be designed for fenceline technology. EPA should clarify that both fenceline and within-the-fenceline technologies can be used and provide details on how implementation would differ between them. API fully expects continuous monitoring technology for methane detection to come within the fenceline and get closer and closer to the source, unlocking emissions reduction potential that is unlikely to be realized by sensors installed on the perimeter. These within-the fenceline technologies will not have many of the limitations of today's fenceline solutions – including no need for wind or meteorological data because these sensors will be in closer proximity to equipment. Limiting the continuous monitoring requirements in this rulemaking to fenceline only would potentially reduce incentives to develop more advanced technology.

3.4.3 Currently available continuous / near-continuous monitoring technology detect methane emissions. The requirement for quantification should be amended.

Current continuous or near-continuous monitors are used to detect emissions and allow for a real-time response by operators; however, these monitors are not and should not be treated as a continuous emission monitoring system like a more traditional "CEMS". These monitors are "high frequency" monitors and not necessarily "continuous" in a traditional sense. The main focus of the monitors should be in the detection of emissions similar to the current OGI framework where the technology is used to find a leak and an operator can then respond, and if appropriate, to fix the leak.

The proposed framework should not be limited by a technology's ability to quantify emissions as this severely limits the types of monitors that can be used and offers a disincentive for operators to deploy the high frequency monitors currently available for deployment. Many technologies on the market today purport to quantify, but industry experience is that the value and accuracy is driven by the system's ability to act as a smoke alarm, where a certain threshold triggers a response system that notifies operators. There is no continuous monitoring technology today that actually "measures" a rate. The "quantification" capability is not derived from the underlying "smoke alarm" sensor but layering that sensor with wind, meteorological and other plume model / inversion model information / assumptions, which has untenable uncertainty.

Therefore, we believe these types of monitors should be considered as effective as the BSER standard, which is quarterly OGI for many larger well sites, central production facilities, and compressor stations. This proposal would have the technologies follow an approach similar to the matrix for other alternate technologies provided in §60.5398b(b) and Tables 1 and 2 to Subpart OOOOb and not follow the action levels in §60.5398b(c).

3.4.4 Continuous / near-continuous monitors should be evaluated against BSER, which is quarterly OGI.

As mentioned, currently available monitors allow for an alarm and response framework that allows operators the ability to evaluate the alarm and mitigate potential leaks. Due to this, continuous monitoring should be compared against the effectiveness of the technology in allowing response and potential repair of leaks against the BSER requirement of quarterly OGI and not based on the type of "fenceline" type framework that has been proposed. Per §60.5398b(c)(1), EPA has defined continuous monitoring as **"***the ability of a measurement system to determine and record a valid methane mass emissions rate of affected facilities at least once for every twelve-hour block."* This equates to daily scans at the facility, which sets an unrealistically high bar for implementation when compared against BSER that sets the most stringent monitoring at quarterly OGI and monthly AVO. The use of high frequency monitors should be consistent with BSER based on the detection capabilities of the monitors.

3.4.5 If EPA keeps its proposed framework for continuous monitoring, the proposed action levels should be revised.

While API overall recommends that continuous monitoring be incorporated with periodic screening to create a single framework for alternative technology, we have concerns with the proposed action levels if EPA choose to keep its proposed separate framework for continuous monitoring. The proposed action levels are based on EPA's FEAST modeling, which does not accurately characterize the effectiveness of AVO and OGI as discussed in Comment 3.1.4. We see merit in including a framework for future technologies that could detect and more accurately quantify emissions, but the currently proposed thresholds are not reflective of actual operations.

Regarding the proposed action levels in §60.5398b(c)(4), API offers the following suggestions:

- **Action levels should be based on detected emissions above an established baseline.** As proposed, the action levels appear to be based on total site emissions, which includes routine or baseline emissions, rather than emissions above an established baseline. Under continuous monitoring, fugitive emissions from leaks are additive to baseline emissions, but they are not additive under AVO/OGI/Method 21 and periodic screening programs. Action levels based on total site emissions effectively sets a limit on site emissions without considering the size or number of emission sources at a site, which could disincentivize the use of continuous monitoring, especially at larger sites. Also, failure to consider baseline emissions would not exclude contributions from other nearby sources of methane emissions including but not limited to other sites, farming activities, graywater trucks, human populations, etc. EPA should revise the action levels to be based on emissions above baseline and propose how operators establish those baseline emissions.

- **The rolling 90-day (long-term) action levels should be removed as they have no equivalent in the AVO/OGI/Method 21 or periodic screening requirements.** Both the AVO/OGI/Method 21 and periodic screening programs require action to address emissions detected during the monitoring; in other words, emissions are compared to an established immediate or short-term threshold. Neither program has a long-term emissions threshold for action like the rolling 90-day action levels proposed for continuous monitoring. A long-term action level is at best a lagging indicator of an event and would make the investigative analysis of an exceedance more challenging. EPA has not clarified how operators should treat exceedances of the short-term action level that could also cause an exceedance of the long-term action level; operators resolve the short-term event in a timely fashion but may still exceed the long-term action level without any additional events or leaks. Based on these various reasons, EPA should either incorporate continuous monitoring completely into the screening matrix or remove the long-term action levels from the separate continuous monitoring framework.

- **The rolling 7-day (short-term) and rolling 90-day (if they remain) action levels should be revised.** The proposed action levels are too low and therefore practically disincentivize the use of continuous monitors. Despite being the most frequent detection method (every 12 hours as proposed), the proposed short-term action levels of 15 or 21 kg/hr are both below 30 kg/hr, which is the detection threshold for the most frequent periodic screening technology (monthly). A typical minimum threshold for actionable detection and notification is 20 kg/hr for today's technology. The lower the action level, the higher uncertainty on which source is causing the detection, and the likelihood for monitors to detect permitted or other background emissions. One potential solution is to have the short-term action level based on a fixed level to address smaller sites (e.g., wellhead only sites) or a variable level from baseline emissions (e.g., 200% of baseline emissions) to address larger sites.

  The long-term 1.2 or 1.6 kg/hr action levels may also be below the baseline emissions for many sites, which would be especially problematic if they represent total site emissions. Some operators, therefore, would effectively be unable to adopt continuous monitoring for NSPS OOOOb or EG OOOOc compliance.

3.4.6 We support timely and flexible follow-up actions to address any leaks found and request similar repair timeframes consistent with §60.5397b and §60.5416.

API supports the flexible language proposed in §60.5398b(c)(6) that describes initiating an investigative analysis to determine the primary reason for the emissions detected. We believe an operator can perform this investigation in numerous ways including using site-specific data. Due to the various ways that continuous monitors may be used for emissions detection, different follow-up actions may be appropriate for this technology when compared to AVO, OGI, or Method 21. While we appreciate the flexibility, we offer the following suggestions so that follow-up actions do not disincentivize the use of continuous monitoring as discussed more generally in Comment 3.1.7:

- **The timeline for initiating the investigative analysis should be extended from 5 calendar days to 5 business days.** Similar to periodic screening, additional time is needed for data validation.

- **EPA should clarify that the investigative analysis and corrective actions can be conducted remotely where feasible.** Operators should be able to conduct an initial evaluation of detected emissions based on SCADA or other operational data rather than sending a person to the site. Due to safety and cost concerns, operators typically limit the amount of time in the field. Remote investigative analysis and corrective actions could also have environmental benefits with reduced vehicle and road dust emissions due to less site visits compared to an onsite analysis required for each instance of detected emissions.

- **EPA should also clarify that limited or full site follow-up OGI surveys should be allowed in response to emissions detected by continuous monitoring depending on the localization performance of the continuous monitor(s)**. A limited or full site follow-up OGI survey may be a useful tool in identifying the source of emissions and therefore appropriate corrective actions. API recommends that the proposed follow-up action process for periodic screening surveys based on localization performance also apply to continuous / near continuous monitoring; refer to Comment 3.3.2 and Figure 2 for more details.

- **The timeline for completing the investigative analysis and initial corrective actions should be 30 days, not 5 days as proposed.** Follow-up actions for continuous monitoring should be consistent with repair timelines for OGI inspections.

- **Consistent with our suggestions in Comment 3.2, we suggest all references to "root cause analysis" be amended to "investigative analysis".**

4.0 Associated Gas Venting from Oil Wells

API recognizes the environmental benefit of eliminating the venting of associated gas from oil wells that do not currently recover gas to a sales line, for injection, or for onsite fuel as its primary use. We disagree with EPA's approach to the control standards proposed including the level of recordkeeping and reporting as it far exceeds the normal level of compliance assurance typically expected from an NSPS. An initial analysis[25] of the impact of the rule on potential production indicates that if the final rule were to eliminate flaring of associated gas, or is implemented in such a way that the practical effect is to eliminate flaring of associated gas, it could result in a substantial loss to production. Such a restriction or implementation would not be supported by API. Should the final rule either expressly or practically eliminate flaring of associated gas, it could be technically infeasible and not cost effective.

We offer the following suggestions with the belief that it is possible to create a manageable regulatory framework that targets the emissions from associated gas at areas without gas gathering infrastructure, including practical compliance assurance, recordkeeping, and reporting.

[25] EPA did not provide sufficient time to fully analyze the Supplemental Proposal and its potential impacts as EPA did not grant API's request for an extension of the comment period. API will continue to evaluate the potential impacts of the Supplemental Proposal.

4.1 We support recovering gas to sales, for reinjection, used as onsite fuel, or routing gas to a control device. We do not support the additional certifications against emerging technologies prior to flaring associated gas.

We continue to support how EPA had described the proposed requirements for associated gas from oil wells in their November 2021 preamble description, but we do not support the hierarchy of the compliance options and associated recordkeeping and reporting requirements as proposed and believe the requirements should be technology neutral. Specifically, we support:

- Recovering gas to sales in §60.5377b(a)(1) (see also Comment 4.2).
- The beneficial use of the associated as onsite fuel proposed in §60.5377b(a)(2).
- Reinjection of the recovered gas into the well or injection of the recovered gas into another well for enhanced oil recovery proposed in §60.5377b(a)(4).
- Flaring the gas such that 95% control efficiency is achieved as proposed in §60.5377b(b).
- An annual reporting requirement focused on periods of venting.

We do not support the requirement to make an infeasibility demonstration and safety and technical certification statements in order to use a flare to reduce these emissions[26]; especially at oil wells that are connected to gas gathering infrastructure and only temporarily flare gas when unable to sell the gas (see also Comment 4.2). We also note that EPA even uses controlling associated gas with a control device such as a flare as justification for the storage vessel requirements (87 FR 74793) *"…these sites also may be subject to standards for oil well with associated gas and the compliance burden is shared between those affected facilities to ensure emissions from both storage vessels and oil wells with associated gas are reduced by 95 percent."* This statement is evidence of EPA's clear expectations of the use of flares at oil well facilities that may have associated gas, making the need for these additional demonstrations arbitrary.

While we support the concept of other types of beneficial use proposed in §60.5377b(a)(3), we do not support the list of options proposed in §60.5377b(b)(1) (methane pyrolysis, compressing the gas for transport to another facility, conversion of gas to liquid, and the production of liquified natural gas). Each option listed requires specialized equipment, capital investment, and additional energy to implement the technology that would generate emissions, some of which may be greater than flaring the associated gas directly. Furthermore, the cost-benefit of the proposed hierarchy of requirements has not been adequately justified by the EPA. In fact, EPA has not considered the technical feasibility, costs, or benefits from any of these options in the updated Technical Support Document[27].

4.2 The provisions for associated gas at oil wells that primarily recover associated gas to sales, for injection, or used for onsite fuel must be adequately delineated from associated gas from oil wells that do not have adequate or accessible gas gathering infrastructure.

Specifically, the notion that *"recovering associated gas from the separator and routing the recovered gas into a gas gathering flow line or collection system to a sales line"* constitutes a control option as proposed under

[26] If retained, the infeasibility demonstration that is a prerequisite to control of associated gas must include consideration of commercial availability of alternatives to pipeline injection and of site economics. Consider, for example, the World Bank's "Zero Routine Flaring by 2030," which seeks "to implement economically viable solutions to eliminate [routine] flaring [of associated gas] as soon as possible."

[27] Supplemental TSD Chapter 6 Associated Gas October 2022 / EPA-HQ-OAR-2021-0317-1578_attachment_7.xlsx

§60.5377b(a)(1) is exceptionally problematic since this explains standard business operations for thousands of wells producing a vital energy resource throughout the country. Including this option within the proposal creates tremendous administrative burden in maintaining the records proposed in §60.5420b(c), without generating environmental benefit as the gas is typically being captured to a sales line already. Selling natural gas is part of our business and this sets a uniquely unjustifiable precedent since operators are in the business to sell as much of the produced gas as possible. In the preamble (87 FR 74779), EPA states *"In addition…a significant addition to the proposed rule is the establishment of requirements for situations when associated gas from an oil well that is primarily either routed to a sales line or used for another beneficial purpose is unable to utilize the gas in that manner due to gathering system or other disruptions."* We agree that these wells should have special requirements for the sporadic, short periods of time that gas cannot be recovered, but the current provisions proposed in §60.5377b(a) do not adequately address associated gas that is typically recovered.

For wells where associated gas from the separator is designed and configured to be recovered, we support simplification of the requirements that focus on the short periods of time when gas is not recovered for sale, injection, or reuse. Specifically, we support flaring the gas by using a permanent or temporary control device[28] that achieves 95% efficiency during periods of time when the associated gas is routed to the control device. In this scenario when a well that is configured to route gas to sales or for reinjection can no longer recover the gas for its primary use, the gas should be immediately routed to the flare as soon as practicable. Since EPA has already acknowledged in the preamble (87 FR 74780) that these situations do occur and are outside the control of the well operator, we do not support making technical or safety demonstrations where disruptions or interruptions in the gas gathering infrastructure result in the need to route the associated gas to a control device for temporary periods. For wells that primarily recover gas for reinjection, conducting compressor maintenance may necessitate temporary periods of flaring. This is reasonable given that a facility is designed with a certain configuration for handling the disposition of associated gas and it is unreasonable to expect facilities to design for multiple uses based on emerging technologies before they can resort to flaring; especially during these short intermittent periods.

Any retention of technical demonstrations, for wells that do not primarily recover associated gas, should include economic viability.

4.3 EPA should include a definition for associated gas.

EPA did not include a defintion of associated gas within §60.5430b or §60.5430c, which we do not believe was EPA's intent. Within the preamble[29] EPA uses the following language when describing associated gas. We believe this language with a few additional clarifications would be appropriate to clearly describe associated gas from oil wells for the purposes of NSPS OOOOb and EG OOOOc. The distinctions we provide explicitly determine which separator the requirements proposed in §60.5377b(a) would apply, providing clear transparency for the regulated community.[30]

[28] A temporary control may be needed in certain situations that an operator may not have planned for or may not have expected. . Allowing both permanent or temporary flare provides flexibility for locations where an existing permanent control device cannot be used or where has not yet been installed.
[29] 87 FR 74778
[30] Without a clear definition, there is uncertainty of what gas EPA seeks to control. For example, some members debate if EPA meant to include flaring from storage vessels. By limiting to the first stage of separation, operators will clearly know what associated gas is applicable.

> *Associated gas means the natural gas which originates at oil wells operated primarily for oil production and occurs either in a discrete gaseous phase at the wellhead or is released from the liquid hydrocarbon during the initial stage of separation after the wellhead.*

4.4 Using associated gas as purge or pilot gas for a control device should be considered beneficial use.

Pilot and/or purge gas allow flares and other control devices to operate safely and effectively to reduce emissions. Furthermore, NSPS OOOOb and EG OOOOc require flares and enclosed combustion devices to have a continuously burning pilot flame when the flare is in use. Enclosed combustion devices are also required to maintain a minimum inlet flow rate, which may require supplemental fuel. In other words, pilot and purge gas are part of the fuel requirements for a flare or enclosed combustion device and are not controlled vent streams.

Since the use of associated gas as an onsite fuel source is one of the proposed beneficial use options in §60.5377b(a)(2), we request that EPA clarify that purge or pilot gas for a control device is considered part of onsite fuel use as shown in the following suggested edit to §60.5377b(a)(2):

> *Recover the associated gas from the separator and use the recovered gas as an onsite fuel source, which may include using the recovered associated gas as purge or pilot gas for a control device or flare.*

As an alternative, EPA could clarify that purge or pilot gas for a control device is considered a useful purpose option under §60.5377b(a)(3).

4.5 Special considerations for handling associated gas from wildcat and delineation wells

In our January 31, 2022 comment letter, we asked EPA to allow certain provisions for wildcat or delineation wells in its proposal with respect to the associated gas from oil well provisions. By nature, these wells are typically located apart from other major oil developments including gathering infrastructure. In many instances an operator will not know or understand the composition of the gas until after the well is drilled. EPA has acknowledged this fact within the definitions that have been published in §60.5430a and maintained in the proposed §60.5430b & §60.5430c where the terms are defined as:

> *Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.*

> *Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.*

In response to our January 31, 2022 comment letter, EPA stated (see 87 FR 74780):

> *"The EPA believes that these situations could warrant an exemption or an alternative standard. However, this proposed rule does not include any exemptions or allowances for these situations due to lack of specific sufficient information. Therefore, the EPA is interested in additional information on gas compositions of associated gas that would make it both unusable for a beneficial purpose and unable to be flared. The EPA is not only interested in why commenters feel these situations warrant an exemption from the associated gas standards as proposed, but also*

> *what methods are currently in use, or could be used, to minimize methane and VOC emissions in these situations."*

Like provisions within NSPS OOOOa for well completions, EPA should allow special considerations for handling associated gas since these activities are exploratory in nature and are typically not located near existing infrastructure. Wildcat or delineation wells will typically only produce for short period of time after flowback ends in order to complete well testing where the production flow rate is determined along with other parameters such as the gas composition before the well is shut-in or capped, which is regulated based on state protocols.[31] These wells are typically located in remote locations far from any form of permanent infrastructure thereby disallowing any beneficial reuse from a practical and logistical standpoint since the gas composition is not known.

As an example, on the Alaskan North Slope, ice roads must be built to access locations where exploration activities are taking place because roads do not exist, and there is not access/connection to existing oil and gas infrastructure. As we described above, characteristics of associated gas from these wildcat / delineation wells is unknown and therefore it is not wise to use as an onsite fuel source. Currently under NSPS OOOOa and under proposed NSPS OOOOb, the initial well flowback is subject to the well completion operation requirements, which allow for use of a completion combustion device. After the flowback ends, the well undergoes cleanout and a well test (extended flowback) is conducted to determine reservoir characteristics. There will still be open top tanks and a combustion device present; however, this equipment will only be utilized for a very short duration. The compliance requirements for both the provisions in §60.5377b(a) or §60.5412b do not allow for realistic implementation for such unique and short-term operations which are not permanently producing oil from a well.

Since wildcat or delineation wells will typically cease production in well under 180 days[32], a temporary or portable combustion device similar to those used to control emissions from well completions is appropriate to reduce VOC and methane emissions. We therefore request EPA allow any associated gas produced from wildcat or delineation oil wells be routed to a completion combustion device (except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a combustion device may negatively impact tundra, permafrost, or waterways). Due to the temporary nature of these activities, the control device compliance requirements should mimic the requirements of control devices utilized for well completions affected facilities, i.e., operated with a reliable continuous pilot flame and no further compliance requirements.

Suggested Redline for inclusion within §60.5377b:

> *For each wildcat or delineation oil well with associated gas at a well affected facility, capture and direct recovered associated gas from the separator to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost, or waterways. Completion combustion devices must be equipped with a reliable continuous pilot flame.*

[31] EPA determined well testing "*conducted immediately after well completion, is considered part of the well completion*" for the purposes of reporting emissions under the Greenhouse Gas Reporting Program (see definition of Well Testing Venting and Flaring in §98.238).

[32] We note the initial performance test for enclosed combustion devices not tested by a manufacturer would not be required until within 180 days after initial startup or start of production. Wildcat or delineation wells typically do not produce for this long to warrant compliance with these provisions. Furthermore, duration of well testing flowbacks from wildcat and delineation wells can be limited to 30 days per other agency regulations/guidance, e.g. BLM's NTL-4A guidance (and proposed Waste Prevention rule) generally limits this activity to 30 days, extension beyond 30 days requires additional approval by the agency.

4.6 EPA's Model Plant Analysis Assumptions

Based on preliminary review of EPA's technical support document that was issued in conjunction of the Supplemental Proposal, the associated gas model plant analysis does not include assumptions reflective of actual proposed requirements.

- In our January 31, 2022 letter, we stated *"a more representative cost for installing a flare suitable to control associated gas would be $100,579, based on the average costs EPA uses for analyzing storage vessel controls."*[33]. We also stated, *"that we did not include the costs from EPA's Workbook 'MP1 Plus Monitors.xlsx' as this would have further increased results due to inclusion of costs for a flow monitor and calorimeter, which EPA did describe in the proposal. If EPA pursues requirements that involve monitors or other requirements such as meeting compliance with §60.18 (as EPA has solicited comment), then additional compliance costs will apply and should be included within EPA's cost analysis."* In the Supplemental Proposal EPA has proposed additional parametric monitoring but has not included these costs in the analysis.

- The EPA should consider model facilities that have existing control devices but now need to install the correct flow and other parametric monitoring equipment as this would be a type of model plant scenario not evaluated by the EPA.

- None of the beneficial reuse emerging technologies have been included within the model plant analysis. It is unclear how EPA has justified the inclusion of these technologies related to costs, feasibility or environmental benefit/disbenefit.

- EPA includes no costs associated with the technical demonstrations proposed. There are direct costs associated with the engineering certification process, whether companies support in-house engineers or leverage third parties. In previous API comments we have provided to the EPA, we estimated certifications to be $2,000 - $9,000.[34]

- The EPA seems to bias the data selected for baseline emissions to fit their expectation and not based on actual reported data. In section 6.3.1 of the technical support document[35] EPA states,

  > *There were 95 facilities/basins that reported associated gas venting emissions [through GHGRP subpart W data]. For each facility/basin, the number of wells venting is reported, along with the total methane vented from all wells. For each facility/basin, we calculated the average emissions per well. These average well emissions ranged from 0.015 tpy to over 2,400 tpy. Almost 20 percent of the facilities/basins had average well methane emissions less than 0.2 tons per year. Explanations of the specific causes of emissions is not provided in the GHGRP subpart W outputs, but it would be expected that routine venting of associated gas would result in emissions greater than this level. In order to avoid selecting a well associated gas venting level that was unreasonably low, a weighted average well emissions level was calculated, using the total emissions from the facility/basin as the weighting factor. The result is an estimated average*

[33] EPA-HQ-OAR-2021-0317-0039
[34] EPA-HQ-OAR-2017-0801
[35] EPA-HQ-OAR-2021-0317-1578

> *annual methane emissions level of 344 tpy. Applying the representative composition yields a representative VOC emissions level of 96 tpy.*

Within these statements, EPA acknowledges that there are very low methane emissions generated from wells that only temporary flare associated gas when the primary recovery method is not available (i.e. routing to sale, for injection, or used as onsite fuel). However, the EPA in this proposal has not made the distinction between facilities that temporarily flare versus those that are truly stranded.

5.0 Control Devices, Covers and Closed Vent Systems

API supports EPA's decision to maintain the 95% control efficiency standard for control devices within NSPS OOOOb and EG OOOOc, and we acknowledge EPA's desire to assure proper control device performance. The following recommendations will allow this goal to be achieved more effectively at well sites, centralized production facilities, compressor stations, and natural gas processing plants. Specifically, the proposed control device and cover and closed vent system requirements present technical feasibility, timing, and cost issues. To address these concerns, NSPS OOOOb and EG OOOOc should allow for more cost-effective monitoring alternatives and better alignment between monitoring requirements for manufacturer-tested enclosed combustion devices and other enclosed combustion devices. Comments concerning both control devices and closed vent systems are presented in this section.

5.1 Emissions detected from covers and closed vents system do not constitute a violation of the "no identifiable emissions" standard provided work practice standards are fully implemented.

EPA states in the Preamble that when a leak is detected in a cover or a closed vent system during a fugitive emissions survey, alternative screening survey, or by a continuous monitoring system, "*the emissions would be considered a violation of the [no identifiable emissions] standard and thus a deviation*"[36]. The "no identifiable emissions standard" or NIE standard is a design and work practice standard (***emphasis added***).

> *You must **design and operate** the closed vent system with no identifiable emissions as demonstrated by §60.5416b(a) or (b), as applicable.37*

As with all other fugitive emissions components, detection of a leak (in this case, defined as identifiable emissions) through routine LDAR monitoring triggers the obligation to repair the leak. If that repair is accomplished according to the specific requirements in the rule, then there is no violation because the work practice has been fully implemented.

EPA long ago rejected the idea that numeric emissions limitations can or should be applied to fugitive emissions components. EPA has presented no reason in the Proposal to depart from its historical approach regarding fugitive emissions from closed vent systems. EPA must make it clear that a closed vent system remains in

[36] 87 FR 74804
[37] §60.5411b(a)(3)

compliance when a leak is detected, provided the associated work practices requiring investigation and repair are followed.

A “no identifiable emissions” or “no detectable emissions” standard cannot constitute a numerical emissions limitation since BSER must be achievable, so the standard must be applied as a work-practice standard. Even the most well-designed and operated system will develop a leak due to wear and tear on equipment. A zero emissions standard for cover and closed vent system components is practically unachievable because some leaks will happen in the normal course of operations (e.g., typical fugitive leaks) and some develop due to causes beyond an operator’s control. Consider that if a leak from a rusty bolt on a pipe flange is only subject to the standard LDAR work practice standard, then a leak from a rusty bolt on a cover or closed vent system should also only be subject to the standard work practice standard. There is no reason why a typical fugitive leak should be treated differently simply because it occurs on a cover or closed vent system.

Additionally, a leak may develop due to malfunctions or a foreign object (e.g., sand or dust), both of which are not reasonably within the control of the operator. Such leaks are not caused by inadequate design or improper operation and cannot constitute a violation of the “no identifiable emissions” standard. API recognizes the possibility of improperly operating a cover or closed vent system (e.g., forgetting to close a thief hatch), but EPA should clearly differentiate these types of leaks from those described above. For these reasons, EPA’s application of the standard as a numerical emission limitation is not only unachievable but will also have will have a chilling effect on companies that aim to do voluntary leak surveillance, and disincentivize the use of more sensitive instruments. EPA should encourage and incentivize operators to conduct additional voluntary monitoring without the fear of an automatic violation if a leak is detected from a cover or closed vent system.

Lastly, CAA § 111(h)(2) provides that a work practice standard should be prescribed in lieu of a standard of performance (i.e., numeric emissions limitation) when “a pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant.” That is precisely the case with EPA’s proposed NIE standards. The NIE standards do not apply to emissions from the storage vessel or equipment to which the closed vent system is installed. Rather, the proposed NIE standard applies to the closed vent system itself. In this case, it is obvious that there is no “conveyance” through which the regulated pollutants would be emitted or captured. To accomplish such an outcome, the closed vent system to which the NIE standard applies would have to be enclosed within another closed vent system or similar permanent total enclosure in order for the regulated emissions to be captured for subsequent control or venting. Requiring such a system would be inordinately costly, highly impracticable, and likely impossible. This is precisely why LDAR standards have been expressed from the inception of such programs almost exclusively as work practice standards. In short, the NIE standard cannot be effectively construed as a zero-emissions standard, as EPA proposes, because no “conveyance” exists that allows for capture of the regulated emissions and application of such a standard to an emissions point.

5.2 Supply chain delays for acquiring flow meters or other monitoring equipment necessitates the initial compliance period must be extended to at least one (1) year after publication in the Federal Register.

Due to EPA’s proposed designation of the applicability date aligned to the November 2021 proposal (see Comment 12.1), operators may not have the adequate flow and net heating value monitoring technology in place for all sites subject to the provisions proposed in NSPS OOOOb, because these additional monitoring requirements were only contemplated but not specifically proposed in that initial proposal. Since EPA’s proposal for consistent control device monitoring requirements regardless of the affected facility will apply to both NSPS

OOOOb and EG OOOOc, the number of control devices subject to monitoring requirements will increase significantly. The current supply chain delay for acquiring flow meters or similar monitoring equipment is currently approximately 6 to 8 months. This delay within the supply chain is expected to be exacerbated based on both NSPS OOOOb and EG OOOOc implementation over the coming years.

In addition to the supply chain delays in acquiring the monitoring equipment, installation of the monitoring equipment for existing control devices will require a hot tap on the control device piping or a site shutdown. A hot tap is a specialized procedure to make new piping connections, such as those required to install monitoring equipment, while the piping remains in service. Hot taps require high flow rates to facilitate heat transfer during welding, and so additional purge gas may be needed depending on the site gas production. This procedure presents a higher safety, fire, and explosion risk.Due to this elevated risk and specialized nature, operators are currently experiencing delays of approximately 4 months or more to schedule a vendor to perform a hot tap.

As an alternative, a site shutdown to install control device monitoring equipment will result in emissions from the shutdown and purging of equipment and piping. Shutdowns at midstream compressor stations or gas plants could result in gas venting, gas flaring, or a shut-in at upstream facilities. A shorter compliance period will multiply these disruptions as operators work to comply with NSPS OOOOb.

In the 2012 NSPS rule[38], EPA allowed implementation for storage vessel requirements to be phased-in to accommodate the vast number of affected facilities and the number of control devices that would be needed to be acquired. Other state rules, such as those in Colorado and New Mexico[39], have allowed for an orderly phase-in period for certain requirements. EPA must consider that a similar compliance schedule is warranted in the proposed NSPS OOOOb and EG OOOOc based on similar constraints and concerns for acquiring the appropriate monitoring equipment that has historically been exempt from control devices for storage vessel affected facilities. The current supply chain delays in acquiring equipment and limited resources to install equipment are expected to be exacerbated by the large number of control devices subject to monitoring under NSPS OOOOb or EG OOOOc.

Based on feedback from members, we request the initial compliance period for control device flow and net heating value monitoring requirements be extended from 60 days after final publication in the Federal Register to at least 1 year after publication in the Federal Register to allow operators time to order and install the necessary meters assuming that the applicability is based on the December 6, 2022 and other our comments concerning reconstruction and modification are addressed. Additional time, at least another year, would be required if the rules are finalized as proposed. Specifically, compliance with the flow and net heating value monitoring requirements at §60.5417b(d)(1)(vii)(A), §60.5417b(d)(1)(viii)(B), and §60.5417b(d)(1)(viii)(D) along with related operational requirements must be extended to allow operators adequate time to procure and install the necessary monitoring equipment where appropriate as various new equipment is installed, or other equipment is modified or reconstructed.

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[38] See EPA's response at 77 FR 49525-49526.

[39] 20.2.50.122.B(3) NMAC and 20.2.50.123.B(1) NMAC

5.3 With the increased number of control devices subject to flow monitoring requirements, the accuracy requirement for flow meters should be ±10% of maximum expected flow.

For manufacturer-tested enclosed combustion devices, EPA is maintaining the current flow monitoring accuracy requirement of ±2% or better[40]. Historically, this requirement only applied to control devices for wet seal centrifugal compressors and was not required for control devices used to reduce emissions for other affected facilities under NSPS OOOO or NSPS OOOOa. Vent gases from centrifugal compressors have relatively stable flow rates while vent gas from storage vessels is intermittent, low pressure, low velocity / flow, and more difficult to measure.

Since EPA is proposing consistent control device monitoring requirements regardless of the affected facility controlled for both NSPS OOOOb and EG OOOOc, the number of control devices subject to flow monitoring requirements will increase significantly under NSPS OOOOb and EG OOOOc.

The ±2% accuracy requirement may not be technically feasible for most commercially available meters nor cost-effective for control devices on every affected facility at well sites, central production facilities, compressor stations, and natural gas processing plants. As mentioned in Comment 5.2, the availability and cost of meters are negatively affected by supply chain constraints and limited resources to install them. API has previously commented[41] on the challenges with flow monitoring at upstream facilities. This level of accuracy is also more stringent than the ±5% accuracy requirement for flare vent gas flow rates at velocities above 1 feet per second under Maximum Achievable Control technology (MACT) standards finalized under 40 CFR 63 SubpartCC (RMACT)[42].

Two types of commercially available flow meters that are commonly used are thermal dispersion meters or ultrasonic meters. Ultrasonic flow meters are the only identifiable meter that can achieve the ±2% accuracy, but this accuracy may decrease under low-flow or low-pressure conditions. While these meters are technically feasible to meet the proposed accuracy requirement, they may not be economically reasonable with an estimated cost of $20,000 to $30,000 each. In EPA's cost analysis for storage vessels controls[43], the cost of a flare with monitoring equipment was estimated but was not used in the subsequent BSER analysis for new or existing sites. Therefore, EPA did not fully consider the cost-effectiveness of the proposed monitoring requirements for control devices. Thermal dispersion flow meters are less expensive but may not meet the accuracy requirement with a typical accuracy of ±5% or better at high flows (accuracy decreases at pressures less than 25 psig). The lower pressure and variable flow rates from certain affected facilities such as storage vessels also make the accuracy requirement difficult to meet. If a control device is used for controlling atmospheric storage tanks only, it will be operating at less than 25 psig and so even a ±5% accuracy may be difficult to achieve; therefore, the flow meter accuracy requirement must consider this likely scenario. In colder conditions, like those experienced in North Dakota and other states, the liquid drop out caused by condensation can also reduce the accuracy of flow meters and make an accuracy of ±2% technically infeasible. Therefore, API proposes that the accuracy for control device inlet flow rate be increased to ±10% of maximum expected flow.

[40] §60.5417(d)(1)(viii)(A) and §60.5417a(d)(1)(viii)(A)
[41] API's December 4, 2015, comments on the proposed Subpart OOOOa and January 31, 2022, comments on the proposed Subparts OOOOb and OOOOc.
[42] 40 CFR 63 Subpart CC Table 13
[43] EPA-HQ-OAR-2021-0317-0039, "StTanks_Control_Costs_v5.1.xlsx" and "EPA_Flares_Calc_Sheet_MP1plusmonitors.xlsx"

5.4 Flow monitoring requirements should be consistent between manufacturer-tested and other enclosed combustion devices.

Manufacturer-tested enclosed combustion devices function similarly to other enclosed combustion devices with the only difference being the party responsible for stack testing; therefore, the proposed flow monitoring requirements should be consistent regardless of whether the device is tested by the manufacturer or owner/ operator. In comparing the proposed flow monitoring requirements for manufacturer-tested enclosed combustion devices at §60.5417b(d)(1)(vii)(A) and other enclosed combustion devices at §60.5417b(d)(1)(viii)(D), the following inconsistencies were noted and should be addressed.

- **No accuracy requirement is specified for other enclosed combustion devices.** As discussed above, the accuracy requirement for flow rate monitoring should be ±5% for both manufacturer-tested and other enclosed combustion devices.
- **Manufacturer-tested devices appear to be limited to flow meters while other enclosed combustion devices may use other parameter monitoring systems.** Other parameter monitoring systems combined with engineering calculations should also be an option for flow monitoring on manufacturer-tested devices especially considering the potential challenges in obtaining and installing a flow meter in a timely fashion. Other parameter monitoring systems are also needed in situations where flow monitoring is infeasible (e.g., low flow scenarios). These other parameter monitoring systems would be more stringent than MACT HH, which allows GRI-GLYCalc™ or other process simulation to calculate inlet flow rate for manufacturer-tested control devices[44].
- **Manufacturer-tested devices do not have an option to exempt the device from flow monitoring.** For enclosed combustion devices not tested by the manufacturer, maximum inlet flow rate monitoring is not required if a demonstration can be made using engineering calculations, and minimum inlet flow rate monitoring is not required if a backpressure valve is properly installed and operated. These alternative compliance options for flow rate monitoring should also be available to manufacturer-tested devices.
- **EPA should clarify that a backpressure preventer is a backpressure valve.** Since backpressure preventer is an unclear term, EPA should use the term "backpressure valve" instead.
- **Additional examples of other parameter monitoring systems should be added to the regulatory text.** To clarify and elaborate on the variety of other parameter monitoring systems that could be used in lieu of a flow meter, EPA should consider adding inlet pressure and line size as additional examples in the regulatory text.

Based on these items, API offers the following recommended redline of flow monitoring requirements for manufacturer-tested control devices in §60.5417b(d)(1)(vii)(A):

> *Except as noted in paragraphs (d)(1)(vii)(A)(1) through (4) of this section, ~~T~~the continuous parameter monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ~~±2~~ ±10 percent or better at the maximum expected flow rate. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure, inlet pressure, line size, and burner nozzle dimensions, to satisfy this requirement. The flow rate at the inlet to the combustion device*

[44] §63.773(d)(3)(i)(H)(*1*)

must be equal to or greater than the minimum flow rate and equal to or less than the maximum flow rate determined by the manufacturer.

(1) *If you can demonstrate, based on the maximum potential pressure of units manifolded to the control device and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the control device cannot cause the maximum inlet flow rate determined by the manufacturer to be exceeded, you are exempt from continuously monitoring for maximum inlet gas flow rate.*

(2) *If you install and operate a backpressure valve which is set to operate at or above the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.*

(3) *Control devices that are exempt from both minimum and maximum inlet gas flow monitoring are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*

(4) *Pressure-assisted flares control devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*

API also offers the following recommended redline of flow monitoring requirements for control devices not tested by the manufacturer in §60.5417b(d)(1)(viii)(D):

Except as noted in paragraphs (d)(1)(viii)(D)(1) through (4) of this section, a continuous parameter monitoring system for measuring the flow of gas to the enclosed combustor or flare. The monitoring instrument must have an accuracy of ±10 percent or better at the maximum expected flow rate. You may use direct flow meters or other parameter monitoring systems combined with engineering calculations, such as line pressure, inlet pressure, line size, and burner nozzle dimensions, to satisfy this requirement.

(1) *If you can demonstrate, based on the maximum potential pressure of units manifolded to the enclosed combustor or flare and applicable engineering calculations for the manifolded closed vent system, that the maximum flow rate to the enclosed combustor cannot cause the maximum inlet flow rate established in accordance with paragraph (f)(1) of this section or the flare tip velocity limit in §60.18 to be exceeded, you are exempt from continuously monitoring for maximum inlet gas flow rate.*

(2) *If you install and operate a backpressure ~~preventer~~ valve which is set to operate at or above the minimum inlet gas flow rate, you are exempt from continuously monitoring for minimum inlet gas flow rate.*

(3) *Flares that are exempt from maximum inlet gas flow monitoring and enclosed combustion devices that are exempt from both minimum and maximum inlet gas flow monitoring are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*

(4) *Pressure-assisted flares and pressure-assisted enclosed combustion devices are not required to have a continuous parameter monitoring system for measuring the inlet flow of gas to the device.*

Given the small size, dispersed nature, and large number of units affected by this rule, these changes would appropriately reduce the burden of compliance while still providing for compliance demonstration and monitoring.

5.5 EPA must provide the minimum inlet flow rate for current manufacturer-tested control devices no later than publication of the final rule so that owners and operators are able to achieve compliance.

In the preamble[45], EPA states that previously tested manufacturer control devices "*would not need to perform new performance tests*" and "*[t]he zero-level at which the combustion control device was tested will be extracted from the previously submitted performance test report and added to the information on the EPA's website*". This minimum flow rate information must be added to the EPA's website[46] no later than publication of the final rule since owners and operators cannot extract the information themselves as the underlying test reports are not currently available on the website. This minimum flow rate information may also not be easily obtained from the manufacturer directly. EPA must provide this minimum flow rate information no later than publication of the final rule so that owners and operators are able to take any necessary action (e.g., purchase of a different control device or operational changes) to achieve compliance. If the minimum flow information is not provided by the publication of the final rule, EPA should consider implementing a longer initial compliance period (see Comment 5.2).

5.6 EPA should allow the use of alternative technologies within the proposed monitoring requirements.

Given the increasing number of control devices subject to proposed monitoring requirements, EPA should allow the use of alternative technologies to meet the monitoring requirements for visible emissions, continuous pilot flame, and minimum net heating value. Well sites, centralized production facilities, and compressors do not have the same utilities and instrumentation resources as refineries, so alternative technologies would provide more cost-effective monitoring of control device performance.

5.6.1 A smoking check should be the primary monitoring method for visible emissions from flares and enclosed combustion devices.

Thousands of flares and enclosed combustion devices will be subject to proposed monthly Method 22 observations and associated recordkeeping. Each of these observations requires 15 minutes and detailed records to document that the observation was conducted according to Method 22. In total, these observations will add up to hundreds to thousands of hours each month and thousands to tens of thousands of hours per year with no added environmental benefit if the device is operating properly. Compliance can more easily be monitored using a monthly smoking check with a record documenting the time of the observation and whether the control device is observed to be smoking. If the device is observed to be smoking, then operator would be able to either 1) assume the device failed the visible emissions requirement and immediately take corrective actions or 2) conduct the 15-minute Method 22 observation to determine whether the device meets the visible emissions requirement. A monthly smoking check could reduce the time required to monitor the device by more than 90%, and this saved

[45] 87 FR 74796
[46] https://www.epa.gov/stationary-sources-air-pollution/performance-testing-combustion-control-devices-manufacturers

time could be used for other tasks with greater environmental benefit (e.g., conducting a required AVO and/or OGI survey while at the site).

5.6.2 Video camera systems should be allowed as an alternative to Method 22.

Since some sites are already equipped with video camera systems, EPA should also allow video cameras as an alternative method to conduct the required monthly smoking check or Method 22 visible emission observations for enclosed combustion devices and flares. Video camera systems are allowed as an alternative to Method 9 observation under Broadly Applicable Approved Alternative Test Method ALT-82[47]. Although these video camera systems have similar supply challenges to other monitoring equipment (see Comment 5.2), they should be an allowed monitoring alternative. To be consistent with the smoking check or Method 22 requirement, the camera would be used to remotely conduct a smoking check and/or 15-minute observation for visible emissions from the control device every month. Owners or operators would keep a record of this remote visible emission observation with similar information required for in-person smoking check or Method 22 observation. Artificial intelligence and machine learning should be allowed to continuously screen the video feed for smoke detection and if smoke is detected, alert the operator that a Method 22 follow-up is required. Making the requirements for video camera systems more stringent than the proposed monthly Method 22 observation would disincentive the use of this alternative. Recordkeeping and reporting of additional video records could pose potential security risks and data storage concerns.

5.6.3 An automatic ignition system with a flame monitoring device should be allowed as an alternative to a continuous pilot flame.

A continuous pilot flame requires propane or other supplemental fuel at sites without fuel gas. For sites with sour gas, a continuous pilot flame requires either using the sour gas as the pilot or bringing in propane or other supplemental fuel to supply the pilot. Burning propane or other supplemental fuel is costly and generates additional emissions when no vent streams are sent to the control device. Similarly, burning sour gas generates additional emissions including SO_2 and potentially uncombusted H_2S. Some state rules, such as New Mexico[48] and Texas[49], allow for the use of an automatic ignition system with a flame monitoring device in lieu of a continuous pilot flame. Therefore, API proposes that an automatic ignition system with a flame monitoring device be allowed as an alternative to a continuous pilot flame.

5.6.4 The minimum net heating value demonstration should be simplified.

EPA should provide flexibility to operators by simplifying its proposed minimum net heating value demonstration alternative to continuous net heating value monitoring. Both the proposed continuous net heating value monitoring and demonstration alternative seem excessive considering that the net heating value of vent streams from affected facilities is typically well above the minimum net heating value requirements. These vent streams consist of mostly hydrocarbons, and the simplest hydrocarbon (methane) has a net heating value of approximately 900 Btu/scf, which is 450%, 300%, or 112% of the minimum net heating value requirement of 200, 300, or 800 Btu/scf depending on the type of control device.

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[47] https://www.epa.gov/sites/default/files/2020-08/documents/alt082.pdf
[48] 20.2.50.115.C(1)(b)(i) NMAC and 20.2.50.115.D(1)(b) NMAC
[49] 30 TAC §106.492(1)(B)

The proposed minimum net heating value demonstration requires continuous monitoring over 10 days or a minimum of 200 hourly samples of inlet gas to the flare or enclosed combustion device. EPA's justification for such an extensive sampling campaign is *"to provide a large sampling set by which to assess the variability of the vent gas sent to the combustion device and to adequately characterize the tails of the distribution."*[50] EPA did not provide additional detail as to why it expects the distribution of vent gas composition to vary enough to potentially be below the required minimum net heating value. Such a large sampling set is unnecessary when the net heating value of vent streams from affected facilities is typically well above the minimum net heating value requirement.

Vent streams from oil well with associated gas, centrifugal compressor, and pneumatic controller in Alaska affected facilities are typically comparable to sales gas or natural gas. In AP-42, natural gas is listed as having a gross heating value of 1,020 Btu/scf (Section 1.4) or 1,050 Btu/scf (Appendix A). The "2011 Gas Composition Memorandum"[51] used in EPA's TSD also suggests net heating values well above the required minimum. Gas composition typically does not change unless certain actions occur at the site, such as adding a new well or refracturing an existing well. Even though the gas composition will typically change with new or modified well streams, composition remains well above the required minimum net heating value.

Vent streams from storage vessel affected facilities consist of more large hydrocarbons than sales gas and have a typical net heating value of 2,000 Btu/scf or more, which is 1,000%, 667%, or 250% of the minimum net heating value requirement of 200, 300, or 800 Btu/scf, respectively. The addition of air from an open thief hatch could drop the heating value of tank vapors below the required minimum net heating value, but the proper operation of thief hatches and other openings are already addressed in the proposed cover requirements.

Vent streams from affected facilities that could potentially be below the minimum heating value requirement include compressors in acid gas service or those at Enhanced Oil Recovery (EOR) facilities. Both situations could have high carbon dioxide (CO_2) content which would lower the net heating value, so operators typically add assist gas or another vent stream with sufficient heating value to facilitate proper control device operation. In these limited situations, API proposes that flow monitoring of the assist gas and vent streams should be allowed as an alternative to the continuous monitoring of net heating value in these limited situations.

Since the vent streams from affected facilities are expected to have sufficient heating value, both the proposed continuous net heating value monitoring and demonstration alternative are economically unreasonable. Calorimeters and other compositional analyzers (e.g., gas chromatographs or mass spectrometers) have an approximate minimum installed cost of $164,000 to $245,000. These monitors may also experience operational issues with entrained liquids in the vent gas stream especially in colder climates and seasons. For the minimum net heating value demonstration alternative, the cost is expected to be $250,000 or more per demonstration. The cost of a vendor-conducted 10-day continuous monitoring campaign is estimated at a minimum of $250,000 to $275,000 while the cost of 200 hourly samples is estimated at a total of $300,000 to $400,000 with an average cost per sample of $1,500 to $2,000 including shipping and analysis.

Since EPA's proposed minimum net heating value demonstration is too onerous and costly, API proposes the following to provide operators the necessary flexibility to comply with net heating value requirements:

[50] 87 FR 74795
[51] EPA-HQ-OAR-2010-0505-0084

- The 10-day demonstration be simplified to a single sample including the use of an appropriate, representative sample or an initial flare compliance assessment with §60.18 using Method 18 of Appendix A. If a representative sample is used, the operator must document why the sample is characteristic of the vent stream composition. If the sample or §60.18 assessment demonstrates that the net heating value is at least 150% of the applicable minimum value (i.e., net heating value of the sample is at least 300, 450, or 1,200 Btu/scf, as applicable), net heating value monitoring would not be required. After the initial demonstration, continuous compliance would be demonstrated through subsequent samples once every 3 years. If the initial or subsequent sample is below 150% of the applicable minimum net heating value, the operator would be required to conduct more extensive sampling as proposed below or install and operator a calorimeter within a reasonable time (suggested as a minimum of 60 days).

- If an initial or subsequent sample does not meet 150% of the minimum net heating value, operators should have the option to conduct a more extensive sampling event with a lower threshold. API proposes that this more extensive demonstration consist of a minimum of 2 hourly samples or 2 hours of continuous monitoring per day for 7 days for a total of 14 samples. The same number of samples is required for a comparable net heating value demonstration under RMACT[52]. Net heating value monitoring would not be required if all 14 hourly averages or samples are above 120% of the applicable minimum net heating value requirement. After the initial 7-day demonstration, continuous compliance would be demonstrated through a grab sample taken once every 3 years. If the initial or subsequent samples are below 120% of the applicable minimum net heating value, the operator would be required to install and operator a calorimeter within a reasonable time (suggested as a minimum of 60 days).

- As with the proposed flow monitoring requirements, net heating value monitoring or demonstration alternative should not be required if operators demonstrate that the net heating value is never expected to below the minimum required value using applicable engineering calculations including process simulation software. This alternative would be similar to MACT HH, which allows GRI-GLYCalc™ or other process simulation software to be used to estimate benzene or BTEX emissions from a glycol dehydration unit[53]. Continuous compliance would be demonstrated through a grab sample taken once every 3 years to verify that the minimum net heating value is being met.

5.7 Minimum operating temperature and associated monitoring requirements should be revised.

NSPS OOOOb proposes a minimum operating temperature of 760 °C and temperature monitoring for enclosed combustion devices that demonstrate that combustion temperature is an indicator of performance during initial performance testing. Other enclosed combustion devices (i.e., those for which combustion temperature is not demonstrated to be an indicator of performance) would be subject to net heating value monitoring requirements. Given the increased number of control devices subject to NSPS OOOOb and EG OOOOc, EPA should revise the minimum operating temperature and associated monitoring requirements in the following ways:

- **Allow operators the flexibility to comply with either temperature or net heating value requirements for enclosed combustion devices that demonstrate that combustion temperature is an indicator of**

[52] §63.670(j)(6)
[53] §63.772(b)(2)(i)

performance. Some enclosed combustion devices, such as thermal oxidizers, are designed with a minimum operating temperature while others are not. Even if a device can demonstrate that temperature is an indicator of performance during testing, maintaining a minimum operating temperature during actual operation may be challenging and require additional supplemental fuel due to the low or intermittent flow of the vent streams. As proposed, a minimum operating temperature with associated monitoring is the only option for enclosed combustion devices that demonstrate combustion temperature is an indicator of performance. For those enclosed combustion devices, operators should be able to comply with net heating value requirements as an alternative.

- **Allow the minimum operating temperature to be established by performance testing.** Rather than a fixed minimum operating temperature, EPA should allow operators the flexibility to comply with a default minimum operating temperature of 760 °C or the value established by the most recent performance testing. The enclosed combustion device may be able to demonstrate compliance at an operating temperature below 760 °C. Also, additional supplemental fuel may be required to keep the device at a minimum operating temperature of 760 °C when it could achieve a 95% control efficiency at a lower temperature. Operators should be allowed to conduct performance testing as needed to establish a new minimum operating temperature.

- **Allow a minimum operating temperature and temperature monitoring for manufacturer-tested devices.** As proposed, the minimum operating temperature and associated monitoring applies only to enclosed combustion devices not tested by the manufacturer. Like operators, manufacturers should be allowed to demonstrate that combustion temperature is an indicator of performance through performance testing and allow temperature monitoring as an option for demonstrating compliance. Operation and monitoring requirements should be consistent between manufacturer-tested and other enclosed combustion devices like our recommendation on flow monitoring in Comment 5.4.

5.8 Manufacturer-tested enclosed combustion devices should continue to be exempt from periodic performance testing.

Under NSPS OOOO and MACT HH, manufacturer-tested control devices are exempt from periodic performance testing. Under NSPS OOOOa, manufacturer-tested control devices on centrifugal compressors are exempt from periodic performance testing if the device has continuous flow monitoring. NSPS OOOOb proposes that manufacturer-tested control devices be subject to both periodic performance testing and continuous flow monitoring. These requirements appear contrary to both the technical challenges in conducting performance tests in the field reiterated by EPA and the agency's intent stated in the preamble (***emphasis added***)[54],

> *''[w]e believe that testing units that are not configured with a distinct combustion chamber* ***present several technical issues that are more optimally addressed through manufacturer testing****, and once these units are installed at a facility, through* ***periodic inspection and maintenance*** *in accordance with manufacturers' recommendations.*
>
> *[Text omitted for brevity.]*

[54] 87 FR 74794

> *For these reasons, we believe the manufacturers' test is appropriate for these control devices with **ongoing performance ensured by periodic inspection and maintenance**. ["] (76 FR 52785; August 23, 2011).*

Given EPA's previous rationale for manufacturer testing, the monitoring requirements proposed under NSPS OOOOb, and the increased number of control devices subject to these monitoring requirements, API recommends that manufacturer-tested control devices continue to be exempt from periodic performance testing.

5.9 Enclosed combustion devices subject to minimum operating temperature and temperature monitoring should also be exempt from periodic performance testing.

Under MACT HH, combustion devices are exempt from periodic performance testing if the device demonstrates during initial performance testing that combustion zone temperature is an indicator of destruction efficiency and operates at a minimum temperature of 760 °C. NSPS OOOO requirements[55] changed this exemption to devices that meet the outlet TOC performance level and that establish a correlation between firebox or combustion chamber temperature and the TOC performance level. NSPS OOOOa[56] adds a temperature monitoring requirement to the NSPS OOOO exemption for control devices on centrifugal compressors.

Like manufacturer-tested devices, NSPS OOOOb proposes to remove this exemption from periodic performance testing. As such, enclosed combustion devices that demonstrate during initial performance testing that combustion zone temperature is an indicator of destruction efficiency are subject to a minimum operating temperature, periodic performance testing, and temperature monitoring. Given the consistent monitoring requirements proposed under NSPS OOOOb and the increased number of control devices subject to these monitoring requirements, API proposes that enclosed combustion devices for which temperature is correlated with destruction efficiency be exempt from periodic performance testing.

To clarify the requested exemptions from periodic performance testing, API offers the following suggested redline of §60.5413b(b)(4)(ii):

> *You must conduct periodic performance tests for all control devices required to conduct initial performance tests, except ~~for a control device whose model is tested under, and meets the criteria of paragraph (d)~~ as specified in paragraphs (b)(4)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(4)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in §60.5420b(b)(12).*
>
> *(A) A control device whose model is tested under and meets the criteria of paragraph (d) of this section.*
>
> *(B) A combustion control device demonstrating during the performance test under paragraph (b) of this section that combustion zone temperature is an indicator of destruction*

[55] §60.5413(b)(5)(ii)(B)
[56] §60.5413a(b)(5)(ii)(B)

efficiency and operates at a minimum temperature of 760 °Celsius or the minimum temperature established during the most recent performance test.

5.10 The continuous monitoring option for organic compound concentration in the control device exhaust may not be technically feasible or economically reasonable. This monitoring option is also meaningless without the corresponding outlet concentration performance standard.

As an alternative to continuous flow monitoring and other similar monitoring requirements, EPA has retained the existing option under NSPS OOOO and OOOOa to use a continuous monitor for organic compound monitoring in the control device exhaust. However, such monitoring may not be a technically feasible or economically reasonable alternative to the other continuous monitoring requirements.

Furthermore, this monitoring option does not make sense since the previous TOC outlet concentration performance standard was not proposed for NSPS OOOOb and EG OOOOc. EPA should clarify if the removal of this alternate performance standard was intentional and how operators should handle compliance for existing control devices that are complying with the TOC concentration standard under NSPS OOOO or OOOOa.

5.11 Technical clarifications for proposed control device requirements.

5.11.1 EPA should clarify requirements for regenerative carbon adsorption systems that use a regenerant other than steam.

For some existing regenerative carbon adsorption systems, residue gas or another regenerant is used instead of steam since the sites typically do not have access to a steam system like a chemical plant or refinery. In the natural gas production and processing industry, natural gas (mostly methane) with a set of heat exchange systems is used to regenerate the carbon beds in place of steam. These systems can be used when there is potential to have air enter the system. A carbon bed does not have a direct fire source which can help limit the potential for a fire in the system. The regeneration cycle is infrequent for these systems. While the proposed requirements for regenerative carbon adsorption systems are unchanged from NSPS OOOOa, EG OOOOc will subject existing sources and control devices to methane standards, and API would like to confirm these regeneration cycles would not be part of the control requirements under this rule. Operators should not be forced to change the operation of their existing control device provided they meet the applicable requirements. Forcing sites to switch to steam regenerant may be technically infeasible or economically unreasonable.

5.11.2 EPA should clarify the proposed requirement language around the presence of pilot flames.

The proposed requirements for control device pilot flames use the following three phrases, each of which could suggest a different meaning:

- A **“continuous burning pilot flame”** means a pilot flame is required at all times regardless of whether the site is operating or vent gas is sent to the control device.

- A **"pilot flame present at all times of operation"** could mean either a pilot flame is required at all times the site is operating or only for those times when the control device is operating (i.e., vent gas is sent to the control device)

- **"Pilot flame while emissions are routed to the control device"** means a pilot flame is required only when vent gas is sent to the device (in other words, at all times of control device operation).

A pilot flame should only be required when emissions are routed to the control device since loss of the pilot flame would result in additional emissions only when vent gas is sent to the device. This clarification would allow for the use of automatic ignition systems (see Comment 5.6.3). This clarification would also be consistent with the compliance requirement found at §60.5412b(b)(1):

> *You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.*

API offers the following redlines that clarify a pilot flame should be required only when emissions are routed to the control device like some state rules including New Mexico[57]:

> *§60.5412b(a)(1)(vii): You must install and operate a continuous burning pilot flame <u>or automatic ignition system</u>.*

> *§60.5412b(a)(3)(iv): You must install and operate a continuous burning pilot flame <u>or automatic ignition system</u>.*

> *§60.5413b(e)(2): A pilot flame <u>or combustion flame</u> must be present at all times ~~of operation~~ <u>while emissions from affected facilities are routed to the control device</u>.*

> *§60.5415b(f)(1)(vii)(A)(1): A pilot flame <u>or combustion flame</u> must be present at all times ~~of operation~~ <u>while emissions from affected facilities are routed to the control device</u>.*

> *§60.5417b(d)(1)(i): For an enclosed combustion control device that demonstrates during the performance test conducted under §60.5413b(b) that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °Celsius, or ±2.5 °Celsius, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature. You also must comply with the requirements of paragraphs (d)(1)(viii)(D) and (E) of this section, and you must install a monitoring device that continuously (i.e., at least once every five minutes) indicates the presence of the pilot flame <u>or combustion flame</u> while emissions <u>from affected facilities</u> are routed to the control device.*

> *§60.5417b(d)(1)(vii)(B): A monitoring device that continuously, at least once every five minutes, indicates the presence of the pilot flame <u>or combustion flame</u> while emissions <u>from affected facilities</u> are routed to the control device.*

[57] 20.2.50.115.C(1)(b)(i) NMAC and 20.2.50.115.D(1)(c) NMAC

§60.5417b(d)(1)(viii)(A): Continuously monitor at least once every five minutes for the presence of a pilot flame or combustion flame using a device (including, but not limited to, a thermocouple, ultraviolet beam sensor, or infrared sensor) capable of detecting that the pilot or combustion flame is present at all times while emissions from affected facilities are routed to the control device. Continuous monitoring systems used for the presence of a pilot flame or combustion flame are not subject to a minimum accuracy requirement beyond being able to detect the presence or absence of a flame and are exempt from the calibration requirements of this section.

§60.5417b(g)(1): A deviation occurs when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is less than the minimum operating parameter limit (and, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section; for flares, when the average value of a monitored operating parameter determined in accordance with paragraph (e) of this section is above the limits specified in §60.5415b(f)(1)(vii)(B); or when the heat sensing device indicates that there is no pilot flame or combustion flame present for any time period while emissions from affected facilities are routed to the control device.

§60.5417b(g)(6)(iii): There is no indication of the presence of a pilot flame or combustion flame for any 5-minute time period while emissions from affected facilities are routed to the control device.

§60.5420b(c)(11)(i)(F)(1): Records that the pilot flame or combustion flame is present at all times ~~of operation~~ while emissions from affected facilities are routed to the control device.

5.11.3 EPA should clarify which elements of the control device monitoring plan apply to heat sensing monitoring devices that indicate the presence of a pilot flame.

The proposed control device monitoring plan requirement includes the following exemption: "…*Heat sensing monitoring devices that indicate the continuous ignition of a pilot flame are exempt from the calibration, quality assurance and quality control requirements of this section.*"[58] However, one of the listed monitoring plan elements uses a thermocouple as an example. This example is confusing since thermocouples could be used as a heat sensing monitoring device for a pilot flame, or as a temperature monitoring device. In the former case, the exemption would apply but not in the latter. EPA should clarify which elements of the monitoring plan apply to heat sensing devices.

Therefore, API recommends the following redline for §60.5417b(c)(2)(ii):

Sampling interface ~~(e.g., thermocouple)~~ location such that the monitoring system will provide representative measurements.

Alternatively, EPA could propose a different example for sampling interface.

[58] §60.5417b(c)(2)

5.11.4 EPA should clarify that control devices are not considered fugitive emissions components and how to address emissions from control devices detected during fugitive emissions monitoring.

While EPA recognizes that "control devices should not be treated as fugitive emissions components"[59], EPA adds confusion by trying to address emissions "caused by a failure of a control device subject to §60.5413b" under the alternative periodic screening requirements. API believes that this requirement is intended to address improper control device operation such as an unlit flare when vent gas is routed to it and recognizes that alternative periodic screenings can be an effective tool at identifying such issues. However, such emissions are not fugitive emissions and would not necessarily be part of the follow-up ground-based monitoring survey of fugitive emissions components or inspections of the cover and closed vent system. Since control devices are required to meet a 95% control efficiency, they will always have the potential for uncombusted emissions that could be detected by OGI or alternative technology. Unclear or inappropriate requirements related to detected emissions from control devices may be a disincentive for the use of alternative leak detection technologies. Therefore, EPA needs to reconsider how to better address emissions from control devices that could be detected during fugitive monitoring surveys. Refer to Comment 3.3.2 and Comment 3.4.6 for API's recommendations concerning follow-up action for alternative technologies.

5.12 Idle control devices at a site should be exempt from performance testing and monitoring requirements.

The proposed NSPS OOOOb and EG OOOOc requirements are unclear on whether idle control devices at a site are subject to performance testing and monitoring requirements. Some state rules, such as Colorado, require control devices be installed based on the potential maximum throughput of a site. For a site, the control devices may be installed and operated in series using pressure-activated valves, meaning that vent gas is sent to the first device until it reaches capacity before the excess vent gas is sent to the second device and so on. In actual operation, sites may never achieve the potential maximum throughput and associated emissions rates, so control devices toward the end of the control system are available but always idle. But even if activated, they would not be needed for purposes of complying with NSPS OOOOb or EG OOOOc.

One potential reading of the proposed NSPS OOOOb and EG OOOOc requirements is that such idle control devices are subject to initial and periodic performance testing and monitoring requirements especially if they are manifolded together. Conducting performance tests on idle control devices could increase in emissions since additional gas would need to be sent to the control devices for the purposes of testing or additional temporary piping installed to route vent gas to the idle control device. Furthermore, a failed performance test on an idle control device would force operators to repair, retrofit, or replace the device, increasing compliance costs with no environmental benefit because the idle device is not expected to be required for compliance. EPA recognized the environmental and cost disbenefit of testing idle emission sources in the federal standards for engines found in NSPS JJJJ[60] and MACT ZZZZ[61]. Similarly, installation of monitoring equipment on idle control devices increases costs with no environmental benefit.

[59] 87 FR 74724
[60] §60.4244(b)
[61] §63.6620(b)

To clarify that idle control devices are exempt from performance testing and monitoring requirements, API offers the following redlines:

> *§60.5400b(a): General standards. You must comply with the requirements in paragraphs (b) through (d) of this section for each pump in light liquid service, pressure relief device in gas/vapor service, valve in gas / vapor or light liquid service, and connector in gas / vapor or light liquid service, as applicable. You must comply with the requirements in paragraph (e) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (f) of this section for each closed vent system and control device ~~used to comply~~ operated for the purpose of complying with equipment leak provisions in this section. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must make repairs as specified in paragraph (h) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (i) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (j) of this section. You must perform the reporting as specified in paragraph (k) of this section. You must perform the recordkeeping as required in paragraph (l) of this section.*

> *§60.5401b(a): General standards. You must comply with the requirements in paragraphs (b) of this section for each pump in light liquid service. You must comply with the requirements of paragraph (c) for each pressure relief device in gas/vapor service. You must comply with the requirements in paragraph (d) of this section for each open-ended valve or line. You must comply with the requirements in paragraph (e) of this section for each closed vent system and control device ~~used to comply~~ operated for the purpose of complying with equipment leak provisions in this section. You must comply with paragraph (f) of this section for each valve in gas/vapor or light liquid service. You must comply with paragraph (g) of this section for each pump, valve, and connector in heavy liquid service and pressure relief device in light liquid or heavy liquid service. You must comply with paragraph (h) of this section for each connector in gas/vapor and light liquid service. You must make repairs as specified in paragraph (i) of this section. You must demonstrate initial compliance with the standards as specified in paragraph (j) of this section. You must demonstrate continuous compliance with the standards as specified in paragraph (k) of this section. You must perform the reporting requirements as specified in paragraph (l) of this section. You must perform the recordkeeping requirements as required in paragraph (m) of this section.*

> *§60.5412b: You must meet the requirements of paragraphs (a) and (b) of this section for each control device ~~used to comply~~ operated for the purpose of complying with the emissions standards for your well, centrifugal compressor, storage vessel, pneumatic controller, or process unit equipment affected facility. If you use a carbon adsorption system as a control device to meet the requirements of paragraph (a)(2) of this section, you also must meet the requirements in paragraph (c) of this section.*

> *§60.5412b(a): Each control device ~~used to meet~~ operated for the purpose of complying with the emissions reduction standard in §60.5377b(b) for your well affected facility, §60.5380b(a)(1) for your centrifugal compressor affected facility; §60.5395b(a)(2) for your storage vessel affected facility; §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska; or either §60.5400b(f) or §60.5401b(e) for your process equipment affected facility must be installed according to paragraphs (a)(1) through (a)(3) of this section. As an alternative to paragraphs (a)(1) through (a)(3) of this section, you may install a control device model tested under*

§60.5413b(d), which meets the criteria in §60.5413b(d)(11) and which meets the initial and continuous compliance requirements in §60.5413b(e).

§60.5412b(b)(1): You must operate each control device ~~used to comply~~ operated for the purpose of complying with this subpart at all times when gases, vapors, and fumes are vented from the affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

§60.5417b: You must meet the requirements of this section to demonstrate continuous compliance for each control device ~~used to meet~~ operated for the purpose of complying with emission standards for your well, centrifugal compressor, pneumatic controller, storage vessel, and process unit equipment affected facilities.

§60.5417b(a): For each control device ~~used to comply~~ operated for the purpose of complying with the emission reduction standard in §60.5377b(b) for well affected facilities, §60.5380b(a)(1) for centrifugal compressor affected facilities, §60.5390b(b)(3) for your pneumatic controller affected facility in Alaska, §60.5395b(a)(2) for your storage vessel affected facility, or either §60.5400b(f) or §60.5401b(e) for your process equipment affected facility, you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with §60.5412b(a)(3), you are exempt from the requirements of paragraph (f) of this section.

5.13 The monitoring plan for control devices does not need to be site-specific.

EPA is proposing that each control device have a site-specific monitoring plan to address the monitoring system design, data collection, and quality assurance / quality control elements. Operators may install the same control device and associated monitoring system across sites in one or more company-defined areas. Similar to the fugitive monitoring plan requirement, EPA should allow monitoring plans for control devices to be based on a company-defined area or a company-wide plan for a specific make and model of control device. Like the fugitive monitoring techniques, control device monitoring is based on the type of control device and monitoring system rather than the site itself. Requiring practically identical site-specific monitoring plans for the large number of control devices increases the administrative burden for operators with no environmental benefit.

5.14 The first repair attempt timeline for covers and closed vent systems may be impractical for certain locations.

While EPA has retained the existing NSPS OOOOa requirements[62] for a first repair attempt on leaks detected from covers or closed vent systems, the 5-day timeline will apply to significantly more sites under NSPS OOOOb and EG OOOOc than NSPS OOOO and OOOOa. This requirement may be impractical for some sites that have access limitations such as those on leased farmland. While API recognizes the historic importance and priority of repairing leaks on covers and closed vent systems, a longer timeline, such as 15 or 30 days, may be more pragmatic since the number of regulated covers and closed vent systems will increase significantly under NSPS OOOOb and EG OOOOc requirements. A different first repair attempt timeline could have the added benefit of

[62] §60.5416a(b)(9) and §60.5416a(c)(4)

making repair timelines consistent between fugitive emissions components and covers and closed vent systems, thus streamlining compliance for operators.

6.0 Storage Vessels

API supports EPA's proposed 6 tpy VOC and 20 tpy methane thresholds for a single storage vessel or a tank battery affected facility at completely new well sites, centralized production facilities, and compressor stations. We also support EPA's retention of the current alternate control standard to maintain the uncontrolled actual VOC emissions from a single storage vessel or a tank battery affected facility at less than 4 tpy VOC and 14 tpy methane. With some technical clarification concerning location, API agrees with EPA's proposed definition for a tank battery.

However, API has concerns regarding EPA's proposed criteria for legally and practically enforceable limits, the proposed definition of modification, and some of the proposed operational requirements. These items are detailed in the following section.

6.1 EPA's proposed criteria for legally and practicably enforceable limits have legal implications beyond this rulemaking and pose permitting challenges.

EPA's proposed requirements for legally and practicably enforceable limits also have legal implications beyond this rulemaking, and these restrictions violate the concept of cooperative federalism. EPA's proposed revisions are wholly inconsistent with EPA's reliance on states to administer the Clean Air Act with regard to Title V and PSD. That is, EPA allows states to establish emission limits on sites that keep sites below Title V and PSD permitting thresholds. EPA should continue to defer to states to determine the appropriate level of monitoring, recordkeeping, and reporting requirements to include in permits rather than imposing a list of strict criteria. This has long been an effective approach to reduce recordkeeping burden while reducing potential emissions.

Just as important as the legal implications discussed in Comment 12.10, the proposed criteria for legally and practicably enforceable limits provide no additional benefit and pose several permitting challenges. Existing permits and associated state programs and rules likely do not meet all the required criteria since EPA has historically deferred to the states on the sufficient monitoring, recordkeeping, and reporting requirements to include in the various levels of permits. For example, permits have proposed annual or rolling 12-month limits on emissions and production since the tank PTE thresholds and NSR permitting thresholds are based on annual emissions. EPA should clarify that such annual limits meet the proposed 30-day averaging time for production limits especially since facilities are typically permitted for a worst-case scenario. Another criterion likely not in existing permits is "*periodic reporting that demonstrates continuous compliance*". Historically, periodic reporting has applied to major sources under Title V and affected facilities regulated under a NSPS or National Emission Standards for Hazardous Air Pollutants (NESHAP), which is a small fraction of the sites that will be regulated under NSPS OOOOb and EG OOOOc. Monitoring, recordkeeping, and reporting requirements in a permit should be tailored to align with the level of authorization with minor sources having less requirements than major sources. For streamlined permitting mechanisms, such as Permits by Rule in Texas, the state agency would have to engage in rulemaking before operators could rely on such permits for determining storage vessel and tank battery PTE. Such rulemaking could take months to years, meaning that operators cannot rely on legally and practicably enforceable limits until those rule updates are finalized and effective.

The second permitting challenge is the methane emissions threshold. For permitting, methane is typically regulated as a greenhouse gas for major sources under the PSD program. States may not be able to permit a methane limit under their minor NSR programs. As such, EPA should clarify that a methane emission limit is not required to be explicitly listed in the permit provided the control device and/or production limits are included that would limit the PTE from a storage vessel or tank battery to less than 20 tpy of methane. Another approach is to allow a VOC limit of less than 6 tpy to serve as a surrogate for the methane emission limit. A potential consequence of requiring an explicit methane emission limit is that existing tanks may have a permit that does not make them an affected facility under NSPS OOOO or NSPS OOOOa but will not be able to obtain an updated permit for the purposes of EG OOOOc applicability.

Assuming operators can obtain permits that meet the proposed legally and practicably enforceable criteria, the permitting effort for the hundreds of thousands of existing storage vessel designated facilities potentially subject to EG OOOOc will take years and be an administrative burden on operators and the state permitting authorities with no environmental benefit. One member has estimated that it will take ten (10) years to obtain updated permits at the current preparation and agency review timelines. This estimated effort will likely take longer as other operators also seek to update permits at the same time. Given the potential enormous re-permitting burden for existing storage vessels/tank batteries, EPA should allow operators to rely on VOC limits as a surrogate for methane in existing permits that have previously been understood to be legally and practicably enforceable.

Overall, EPA's proposed requirements for legally and practicably enforceable limits have broad legal implications and impose real permitting challenges. The combined effect is contrary to the historical intent under NSPS OOOO and NSPS OOOOa, which is to lessen the administrative burden while still achieving the desired environmental benefits. API believes that improving the clarity of the storage vessel applicability criteria is a worthwhile effort and offers the following redline for §60.5365b(e)(2)(i):

> *For purposes of determining the applicability of a storage vessel tank battery as an affected facility, a legally and practicably enforceable limit ~~must~~ may include the elements such as those provided in paragraphs (e)(2)(i)(A) through (F) of this section.*

6.2 The proposed requirements for a modification and reconstruction of a tank battery require additional technical clarifications.

EPA's proposed definitions of reconstruction or modification for a tank battery require several clarifications. First, the proposed definition for reconstruction is internally inconsistent. For a tank battery consisting of more than one storage vessel, reconstruction is based on replacing at least half of the storage vessels based on the assumption that "*the cost of replacing storage vessel components such as thief hatches and pressure relief devices, in comparison to the cost of constructing an entirely new storage vessel affected facility, will not exceed 50 percent of the cost of constructing a comparable new storage vessel affected facility*."[63] However, for a tank battery consisting of a single storage vessel, the existing provisions of §60.15 apply on the chance that the cost of replacement storage vessel components could be 50% or more of the cost to construction a comparable new storage vessel. Either the cost depreciable components on a storage vessel other than the tank itself could be 50% or more of the cost of a new comparable tank or not. Practically, this inconsistency means that operators would have to track the cost of storage vessel component replacements for single storage vessel tank batteries, but not for multi-vessel tank batteries. For both single and multi-vessel tank batteries, operators should have the option

[63] 87 FR 74801-74802

to track either storage vessel replacements or all depreciable components. Based on this recommendation, API offers the following redline of §60.5365b(e)(3)(i):

> *"Reconstruction" of a tank battery occurs when the provisions of §60.15 are met for the existing tank battery ~~any of the actions in paragraphs (e)(3)(i)(A) or (B) of this section~~ and results in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section. As an alternative to the provisions of §60.15, an operator may determine reconstruction has occurred if at least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel and results in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.*
>
> ~~*(A) The provisions of §60.15 are met for the existing tank battery ; as an alternative to the provisions of §60.15, At least half of the storage vessels are replaced in the existing tank battery that consists of more than one storage vessel; or*~~
>
> ~~*(B) The provisions of §60.15 are met for the existing tank battery that consists of a single storage vessel.*~~

Secondly, EPA's proposed definition of modification requires clarification. API supports the first two proposed criteria for modification found in §60.5365b(e)(3)(ii)(A) and (B): "*A storage vessel is added to an existing tank battery*" and "*One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases*". Both these changes require capital expenditure on the potential affected facility (i.e., the tank battery) and would increase emissions. However, the proposed criteria in §60.5365b(e)(3)(ii)(C) and (D) regarding increases in liquid throughput are too broad and is inconsistent with §60.14(e)(2). Per 40 CFR 60.14(e)(2), an increase in throughput for a storage vessel, accomplished without a capital expenditure on that storage vessel, is not considered a modification. EPA has not fully explained why it is proposing to deviate from the historical legal understanding of modification which requires both an increase in throughput and a capital expenditure on the storage vessel or tank battery. Also, increases in liquid throughput at well sites, central production facilities, and compressor stations are difficult to track as sites typically track liquid throughput using tank gauging rather than flow meters. Due to the historic understanding of modification and practical challenges of tracking liquid throughput, **API believes that §60.5365b(e)(3)(ii)(C) and (D) should be removed from the definition of modification**. [64]

However, if EPA decides to include increases in liquid throughput as a criterion for modification, API offers the following recommendations:

- **The increase in liquid throughput must also be accompanied by a capital expenditure on the tank battery itself.** Actions, such as drilling a new well or fracturing or refracturing an existing well, could increase liquid throughput and require capital expenditure but not necessarily on the tank battery itself.

[64] Please see Section 11.6 of our comments on the original proposal for overarching legal comments on the proposed modification definitions. We note that EPA appears to have responded in part to these comments by providing that a modification to a tank battery occurs only when specified actions "result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii)" (the PTE-based applicability thresholds for storage vessels). But we note that EPA's proposed PTE criteria apply to an annual PTE and not, as specified in § 60.14, a short-term measure of PTE (such as lb/hr). This is a significant change in how a potential emissions increase should be considered in determining the existence of a modification because the annual PTE basis in practice likely results in a more expansive modification definition because the short term PTE of storage vessels in almost all cases will be much higher than an annual value, which means that more variation in actual short term emissions can be accommodated without triggering a modification than under an annual metric. EPA fails to explain why it has shifted from a short-term to an annual basis for determining emissions increases associated with a change. As a result, we do not have a reasonable opportunity to understand EPA's rationale and to provide meaningful comments.

These actions would not be considered modifications to the tank battery unless there is capital expenditure on the tank battery itself. This recommendation would make NSPS OOOOb consistent with NSPS A.

- **Reference to process unit in §60.5365(e)(ii)(C) should be removed since process unit is defined such that they should not exist at well sites and centralized production facilities.** Process unit is a term specific to natural gas processing plants and does not apply to well sites and centralized production facilities.

- **Well sites and centralized production facilities should also be allowed to compare liquid throughputs to limits in a legally and practicably enforceable permit like compressor stations and natural gas processing plants.** EPA should be consistent and allow well sites and centralized production facilities to compare liquid throughputs to limits in a legally and practicably and enforceable permit since such a permit can be relied upon for the PTE determination for all sites. **In the absence of a legally and practicably enforceable limit, all sites should be allowed to compare liquid throughputs to those used to design the existing cover and closed vent system in operation when a potential modification action occurs.** These recommendations would also make modification criteria consistent for all sites and clearly define what an increase in liquid throughput is.

Based on these recommendations, API offers the following redlines to §60.5365b(e)(3)(ii):

> *"Modification" of a tank battery occurs when any of the actions in paragraphs (e)(3)(ii)(A) through ~~(D)~~(C) of this section result in the potential for VOC or methane emissions to meet or exceed either of the thresholds specified in paragraphs (e)(1)(i) or (ii) of this section.*
>
> *(A) A storage vessel is added to an existing tank battery;*
>
> *(B) One or more storage vessels are replaced such that the cumulative storage capacity of the existing tank battery increases; or*
>
> *~~(C) For tank batteries at well sites or centralized production facilities, an existing tank battery receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput from actions, including but not limited to, the addition of a process unit or production well, or changes to a process unit or production well (including hydraulic fracturing or refracturing of the well).~~*
>
> *~~(D)~~(C) ~~For tank batteries at compressor stations or onshore natural gas processing plants,~~ A capital expenditure occurs at an existing tank battery, when that existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (i.e., prior to an action in paragraphs (e)(3)(ii)(A), (B) or ~~(D)~~(C) of this section) determination of the potential for VOC or methane emissions; or in the absence of a legally and practicably enforceable permit, a capital expenditure occurs at an existing tank battery, when that existing tank battery receives additional fluids which cumulatively exceed the throughput used in the most recent (i.e., prior to an action in paragraphs (e)(3)(ii)(A), (B) or (C) of this section) design of the storage vessel cover(s) and closed vent system.*

6.3 Additional technical clarifications to proposed definitions are warranted to clarify applicability of certain requirements for tank batteries.

Since the proposed requirements for NSPS OOOOb and EG OOOOc will apply for the tank battery, there are additional technical clarifications to proposed definitions in §60.5430b and §60.5430c that will provide clarity for implementation of the proposed requirements given the new applicability criteria. We support EPA's proposed definition for tank battery based on storage vessels that are manifolded together for liquid transfer, but offer a minor clarification on respect to its location as follows:

> *Tank battery means a group of all storage vessels that are manifolded together for liquid transfer. A tank battery may consist of a single storage vessel located at a well site, central production facility, compressor station, or natural gas processing plant if only one storage vessel is present.*

This clarification addresses the situation of a single storage vessel not located at a well site, central production facility, compressor station, or natural gas processing plant (e.g., drip station along a pipeline). These storage vessels typically have low throughput and methane and VOC emissions. In §60.5365b(e)(2)(ii) and §60.5365b(e)(2)(iii), EPA does not describe how to determine PTE for tank batteries at location other than a well site, centralized production facility, compressor station, or natural gas processing plant. Therefore, API believes that the agency did not intend to regulate these low-emitting tanks with these proposed rules.

6.3.1 The definition of compressor station must be clarified with respect to the storage vessel applicability provisions in §60.5365b(e).

With the introduction of the newly defined central production facility, an additional clarification is needed for when and how to calculate the tank battery PTE at well sites and central production facilities that may have compression versus at a compressor station. The EPA makes this distinction clearly for how to consider the fugitive emission monitoring by referencing §60.5397b in the definition of compressor station. As an example, consider a reciprocating compressor at an oil processing facility. The facility would be a "*tank battery at a well site or centralized production facility*" under §60.5365b(e)(2)(ii) and yet also a "*tank battery located at a compressor station*" as used in §60.5365b(e)(2)(iii).

We therefore request EPA also clarify the storage vessel requirements in a similar way by referencing of §60.5365b(e) in the definition of compressor station as follows:

> *Compressor station means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations. The combination of one or more compressors located at a well site, centralized production facility, or an onshore natural gas processing plant, is not a compressor station for purposes of §60.5365b(e) and §60.5397b.*

In terms of the PTE calculations, centralized production facilities should be considered like compressor stations and natural gas process plants because the storage capacity is typically based on "a projected maximum average daily throughput". Therefore, API offers the suggested redlines for §60.5365b(e)(2)(ii) and §60.5365b(e)(2)(iii).

> *(ii) For each tank battery located at a well site ~~or centralized production facility~~, you must determine the potential for VOC and methane emissions within 30 days after startup of production, or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, except as provided*

in paragraph (e)(5)(iv) of this section. The potential for VOC and methane emissions must be calculated using a generally accepted model or calculation methodology that accounts for flashing, working and breathing losses, based on the maximum average daily throughput to the tank battery determined for a 30-day period of production.

(iii) *For each tank battery located at a centralized production facility, compressor station or onshore natural gas processing plant, you must determine the potential for VOC and methane emissions prior to startup of the compressor station or onshore natural gas processing plant or within 30 days after an action specified in paragraphs (e)(3)(i) and (ii) of this section, using either method described in paragraph (e)(2)(iii)(A) or (B) of this section.*

Another suggested solution is to harmonize the PTE calculation requirements for all sites based on the requirements proposed for compressor stations and gas plants.

6.3.2 A storage vessel located at a well site, central production facility, compressor station, or natural gas processing plant used to alleviate dangerous, or emergency events must be clearly excluded from the definition of storage vessel.

At some facilities, storage vessels may be installed for the sole purpose of providing relief from pressure vessels during emergencies. Previously, these storage vessels would not trigger applicability as a single emergency use vessel was unlikely to exceed 6 tpy VOC threshold under NSPS OOOO or NSPS OOOOa. These tanks now present a challenge with the new applicability threshold proposed in NSPS OOOOb and EG OOOOc for the tank battery. At the state level, emergency use tanks are exempt from control requirements from states and local regulations because state agencies such as California's Air Resources Board (CARB) or San Joaquin Valley Air Pollution Control Board (SJVAPCD) have recognized that these tanks are used in rare and extreme situations for the safety of people and nearby infrastructure.[65,66] We request EPA provide an exclusion for emergency use tanks from the definition of storage vessel as follows:

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of §60.5395b(c)(1) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

- *Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by §60.5420b(c)(5)(iv), showing that the vessel has been located at a site for less than 180*

[65] CARB O&G Regulation, 17 CCR 95668(a)(2)(E): Separators, tanks, and sumps that have contained crude oil, condensate, or produced water for 45 calendar days or fewer per calendar year provided that the owner or operator maintains, and can make available at the request of the ARB Executive Officer, a record of the number of days per year in which the separators, tanks, or sumps have contained liquid.

[66] The SJVAPCD has defined an emergency in some permits as: an unforeseeable failure or malfunction of operating equipment that: (1) is not due to neglect or disregard of air pollution laws or rules; (2) is not intentional or the result of negligence; (3) is not due to improper maintenance; and (4) is necessary to prevent or control an unsafe situation.

consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

- *Process vessels such as surge control vessels, bottoms receivers or knockout vessels.*
- *Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.*
- *Vessels that only receive crude oil, condensate, intermediate hydrocarbon liquids, or produced water due to an unforeseeable failure or malfunction of operating equipment that is necessary to prevent or control an unsafe situation and contains the crude oil, condensate, or produced water for 45 days or less per calendar year.*

6.3.3 EPA should clarify that location is not a restriction on the use of a floating roof tank.

In §60.5395b(b)(2), EPA correctly prohibits the use of a floating roof if the storage vessel or tank battery has flashing emissions. However, EPA also prohibits the use a floating roof at a well site or centralized production facility. Flashing emissions alone, regardless of location, should prohibit the use of a floating roof tank because flashing emissions, not location, could prevent proper operation of a floating roof.

API offers a recommended redline in Comment 6.5.

6.4 The requirement to manifold the vapor space of each storage vessel in the tank battery is overly prescriptive and unnecessary.

As part of the control requirements for storage vessel affected facility, EPA proposes that "*The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels in the tank battery*"[67]. This requirement to manifold the vapor space of each storage vessel in a tank battery is unnecessary and restricts an operator's flexibility in achieving compliance with the required 95% emissions reduction. An operator should be able to install any number of control devices and manifold the vapor space of the storage vessels from one or more tank batteries into one or more closed vent systems so that each control device is properly sized for the expected vent gas flow rate.[68] The requirement to manifold the vapor space of a tank battery may also cause confusion with the proposed definition of tank battery which is based on storage vessels manifolded together for liquid transfer.

API offers a recommended redline in Comment 6.5.

6.5 EPA should provide an exemption from control requirements due to technical infeasibility if the control device or VRU would require supplemental fuel.

With the change in affected facility from a single storage vessel to a tank battery, control devices will be required for a longer time compared to NSPS OOOO and NSPS OOOOa – until the actual uncontrolled emissions from the tank battery (versus each individual storage vessel) are below 4 tpy VOC and 14 tpy of methane. This longer

[67] §60.5395b(b)(1)(ii)
[68] If not corrected, EPA's failure to consider these obvious and important aspects of its proposed manifolding requirement would render such a requirement arbitrary and capricious. Motor Vehicle Mfrs. Assn. v. State Farm Mut. Automobile Ins. Co., 463 U.S. 29, 43 (1983).

period for the control requirement will increase the likelihood that some control devices or VRUs will require supplemental fuel to be technically feasible. As discussed in Comment 5.6.3 for control device pilot flames, operators may have to bring propane for supplemental fuel for sites without fuel gas or burn additional sour fuel gas. As such, API recommends EPA consider an exemption from control requirements for a tank battery if use of a control device or VRU would be technically infeasible without supplemental fuel for pilot flame or other purposes. Such exemptions currently existing in state regulations for storage vessels and tank batteries including Colorado. Based on the language for the Colorado exemption, API offers the following recommended redlines to the control requirements in §60.5395b(b), which also includes the previous comment:

Control requirements.

(1) Except as required in paragraphs (b)(2) and (b)(3) of this section, if you use a control device to reduce methane and VOC emissions from your storage vessel affected facility, you must meet all of the design and operational criteria specified in paragraphs (b)(1)(i) through ~~(iv)~~ (iii) of this section.

(i) Each storage vessel in the tank battery must be equipped with a cover that meets the requirements of §60.5411b(b);

~~*(ii) The storage vessels must be manifolded together with piping such that all vapors are shared among the headspaces of the storage vessels in the tank battery;*~~

~~(iii)~~(ii) The tank battery must be equipped with ~~a~~ one or more closed vent systems that meet~~s~~ the requirements of §60.5411b(a) and (c); and

~~(iv)~~(iii) The vapors collected in paragraph~~s~~ (b)(1)(ii) ~~and (iii)~~ of this section must be routed to a control device that meets the conditions specified in §60.5412b(a) or (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(2) For storage vessel affected facilities that do not have flashing emissions ~~and that are not located at well sites or centralized production facilities~~, you may use a floating roof to reduce emissions. If you use a floating roof to reduce emissions, you must meet the requirements of §60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb. You must submit a statement that you are complying with §60.112b(a)(1) or (2) with the initial annual report specified in §60.5420b(b)(1) and (8).

(3) You may apply to the Administrator for an exemption from the control requirements in paragraphs (b)(1) of this section if the use of a control device would be technically infeasible without supplemental fuel. Such request must include documentation demonstrating the infeasibility of the control device.

7.0 Natural Gas-Driven Pneumatic Controllers

Pneumatic controllers play a pivotal role in the safe operations at oil and natural gas facilities – including at well sites, central productions facilities, compressor stations, and processing plants. In our review of the proposed requirements EPA has not adequately addressed some of the major concerns we identified in our January 31, 2022 comment letter.[69] EPA has severely overstated the deployment capabilities for solar installations to power oil and gas infrastructure in support of their proposal, which indicates a continued lack of understanding of how pneumatic controllers (and pneumatic pumps) would be converted to achieve a non-emitting standard.

For NSPS OOOOb, we support the use of non-emitting pneumatic controllers, contingent on clarifications as described herein, for newly constructed, modified or reconstructed well sites, central production facilities, and compressor stations. We also support EPA excluding emergency shutdown devices from these provisions as it allows for safety in case of emergency.

For existing natural gas-driven pneumatic controllers under NSPS OOOOc, we continue to maintain that 1) adequate time and phase-in must be provided to properly account for the magnitude and scale of sites converting to non-emitting controllers and 2) it is most appropriate to focus conversion to non-emitting controllers at facilities with the largest number of controllers (see Comment 7.5). To effectively do this, the use of low continuous bleed or intermittent natural gas-driven pneumatic controllers should be allowed and should be monitored periodically for proper functioning at the frequency specified in §60.5397c. An initial analysis[70] of the potential impact of the rule should it require conversion to non-emitting pneumatic controllers at all existing facilities shows that it could result in the premature shut-in of a significant percentage of existing wells, particularly when considered in context with the proposed monitoring requirements[71]. EPA should allow additional flexibility in this area as we have described to allow states to preserve the remaining useful life of facilities.

7.1 Adequate implementation time must be provided for pneumatic controller and pneumatic pump requirements under both NSPS OOOOb and EG OOOOc.

As we have stated earlier, adequate time is required to implement the proposed control standards as they fundamentally shift how pneumatic controllers and pneumatic pumps have typically been operated. While new surface locations can typically plan for controls during site design, the supply chain delays pose a genuine and significant concern for all aspects of implementing the pneumatic controller requirements. Anecdotal evidence from one operator that is currently conducting retrofits in New Mexico has identified that air compression equipment is in short supply with around 8 months of delays and another operator that has been piloting solar panel instrument air systems is now experiencing delays of 18 to 24 months on previously made orders. While eventually the market will rise to meet this demand, that market correction has not yet been realized and presents very real concerns for our members. Currently there are hundreds of operators attempting to order equipment for thousands of sites. While we are generally supportive of the proposed requirements (with the necessary and specific clarifications that we have requested), the current proposed timeline for compliance is unrealistic due to global circumstances beyond any operator's ability to control or influence.

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[69] EPA-HQ-OAR-2021-0317-0808
[70] EPA did not provide sufficient time to fully analyze the Supplemental Proposal and its potential impacts as EPA did not grant API's request for an extension of the comment period. API will continue to evaluate the potential impacts of the Supplemental Proposal.
[71] See Comment 2.0

As anecdotal evidence, our members operating in New Mexico are currently working through retrofits of facilities in compliance with state regulations. Instrument air systems are currently on backorder with a wait time of approximately 8 months. This wait time is expected to be exacerbated when EPA's final rule takes effect. Once equipment is received, only 1-3 facilities can be retrofit per operator per week based on type or size of the facility, weather conditions, etc. This means for any given operator, only approximately 50-150 retrofits can successfully take place in a single year. For operators with thousands of new, modified and existing locations, the current proposed timelines are untenable.

Based on EPA's proposed November 2021 applicability date, there are thousands of sites that may now require retrofit under NSPS OOOOb. Since operators are currently experiencing 6-to-8-month delays in acquiring the necessary control equipment for instrument air system conversions, we suggest EPA amend the requirements to reference "upon receipt of equipment" similar to how certain delay of repair provisions have been framed within other regulations.

For pneumatic controllers and pumps under EG OOOOc, given all of the existing sites in the U.S. and the implementation aspects outlined above, we continue to have serious concerns that 5 years for conducting retrofits of this magnitude would not provide adequate time given current and anticipated supply chain delays. Because of these constraints for EG OOOOc, EPA should consider a longer phase-in period where facilities with the largest number of controllers are retrofit first.

7.2 For NSPS OOOOb and EG OOOOc, EPA should allow the routing of emissions from natural gas-driven controllers to a control device.

We continue to suport the routing of certain controller emissions to a flare or other combustion device. In its analysis, EPA dismisses this option by finding that routing pneumatic controller vent gas to a process is cost-effective and thus BSER; however, EPA's analysis fails to account for the cost-effectiveness of the incremental 5% of methane and VOC emissions reductions achieved when comparing routing to process against routing to a control device, which conservatively assumes a control device will achieve only 95% reduction.[72] In many cases, the actual performance of a control device exceeds 98% control. Instead, EPA's analysis focuses on the cost-effectiveness of no control against 100% control. API requests that EPA include routing to a control device as a compliance standard under NSPS OOOOb and EG OOOOc. If EPA does not adopt routing to a control device as an emissions reduction standard, it must demonstrate as cost-effective the incremental 5% of emissions reductions achieved through routing to a process or converting to instrument air.[73]

As an example, one facility may choose to install an instrument air system to convert most natural gas-driven pneumatic controllers on site, but emissions from certain types of controllers that are associated with the flare system itself (e.g. back pressure valve[74]) could more easily route emissions to the flare header. By EPA not allowing for this site configuration, some operators may need to reconfigure controllers that are currently already

[72] 87 Fed. Reg. at 74765-66.

[73] As further support for the above, API responds to EPA's request for information regarding whether vapor recovery units (VRU) are ever necessary to route pneumatic controller vent gas to a process. While it is feasible for operators to route pneumatic controller vents to a downstream process that operates at a lower pressure, a VRU is necessary if no such lower-pressure destination exists or is of limited availability. Installation of a VRU is capital intensive, and VRU maintenance is costly and challenging, especially in extreme weather climates. Where downstream process pressure exceeds vent gas pressure, the pneumatic controller vent gas cannot feasibly route to a downstream process without compression. If EPA is unwilling to allow routing of pneumatic controller vent gas to a control device as an emissions reduction standard on the same footing as routing to a process, EPA should allow routing to a control device where routing to a process is infeasible (taking into account technical and economic considerations), and define infeasibility to include scenarios where routing to a process requires a VRU.

[74] Back pressure valves can be routed to the flare when they are in close proximity to the flare header since they only actuate when there is an over pressurization.

routed to a flare or other combustion device. In this scenario, VOC and methane emissions from these routed controllers are already reduced by 95% or more. EPA has provided no basis for not authorizing routing to control as an option.

Adopting this methodology as a compliance standard can be achieved by amending the proposed definition of "self-contained pneumatic device" to include natural gas-driven controllers routed to control devices in that definition (refer also to Comment 7.3). Such a revision is consistent with both New Mexico and Colorado's regulations – which define non-emitting to include pneumatics routed to combustion.

7.3 Additional technical clarifications are warranted to clarify applicability of certain natural gas-driven pneumatic controller requirements.

While we support inclusion of flexible solutions to reduce emissions from natural gas-driven pneumatic controllers, we have identified critical aspects of the proposed provisions that require technical clarification or simplification as we have outlined herein.

7.3.1 Suggested clarifications to certain proposed definitions related to pneumatic controllers in NSPS OOOOb and EG OOOOc.

There are some additional technical clarifications to proposed definitions in §60.5430b and §60.5430c that will provide clarity for implementation of the proposed requirements given the new applicability criteria as proposed. There are many types of automated instruments that maintain a process condition that are not pneumatic controllers. Many of the proposed definitions must clearly identify pneumatic controllers from these other instruments and be more specific to avoid confusion.

> ***Bleed rate*** *means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a fixed orifice in a pneumatic controller.*
>
> ***Continuous bleed*** *means a natural gas-driven pneumatic controller that is designed with a continuous flow of ~~pneumatic supply~~ natural gas from ~~to~~ a fixed orifice ~~pneumatic controller~~.*
>
> ***Non-natural gas-driven pneumatic controller*** *means an automated process control device that utilizes instrument air or hydraulic fluid as the motive force to change valve position. ~~Instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.~~*
>
> ***Pneumatic controller*** *means an automated instrument that manipulates a valve's position with pressurized gas to ~~used for~~ maintain~~ing~~ a process condition such as liquid level, pressure, delta-pressure and temperature.*
>
> ***Self-contained pneumatic controller*** *means a natural gas-driven pneumatic controller in which the motive gas is not vented to the atmosphere but captured ~~releases gas~~ into t~~he~~ downstream piping for process use, sales or control such that there are no direct methane or VOC emissions from the controller.~~, resulting in zero methane and VOC emissions~~*

7.3.2 EPA must clarify the pneumatic controller requirements in NSPS OOOOb and EG OOOOc apply after startup of production and to stationary equipment only.

We agree with EPA'a assertion in the preamble where (87 FR 74759) *"The EPA acknowledges that the focus of the BSER analysis has been on stationary sources and pneumatic controllers that are part of the routine operation of oil and natural gas facilities."* The zero-emissions requirements are not justified for short term controller usage related to non-stationary sources.[75] Retrofitting controllers located on temporary equipment requires significant engineering design that has not been adequately evaluated to identify if these options are even possible, nor technically achievable nor practically attainable. Pneumatic controllers located on temporary or portable equipment should be allowed to operate as low-bleed or intermittent as needed for proper functioning of the temporary equipment. Some examples of temporary equipment or activities that should be excluded from the proposed provisions include the following:

- **Temporary Equipment (such as compressors):** Operators may utilize a small injection compressor to assist in ramping up production for new wells that have recently ended flowback. These compressors are typically skid mounted and located on site for as few as 30 days after the startup of production. These compressors contain a handful of pneumatic controllers to assist in proper function on the unit and may sometimes be leased from a third party. Another example is the use of a temporary compressor at a wellsite that is needed in anticipating gathering system high line pressure during new gathering system infrastructure build-out, which may occur for a few months. We ask that EPA exclude any natural gas-driven pneumatic controllers on equipment that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 180 consecutive days. This approach is consistent with language describing applicability of temporary storage vessels under NSPS OOOO, NSPS OOOOa, proposed NSPS OOOOb, and proposed EG OOOOc.

- **Drilling and Completion Activities:** As EPA is aware, drilling and completion activities require specialized temporary use equipment that is often contracted by third-party operators. Any pneumatic controllers associated with drilling and completion equipment should be excluded from the zero-emitting controller requirements, which can be accomplished by clarifying that the requirements for pneumatic controllers are not applicable until after the startup of production like other provisions within the proposed standards.

7.3.3 Under NSPS OOOOb, EPA must clarify that modification and reconstruction is limited to natural gas-driven pneumatic controllers.

Throughout the proposed NSPS OOOOb and EG OOOOc, EPA uses the terms 'natural gas-driven pneumatic controller' and 'pneumatic controller' interchangeably. EPA must be clear that the affected facility and other applicability language is specific to natural gas-driven pneumatic controllers. This clarification is especially important as these terms are used within the description for modification and reconstruction. For example, an existing well site that is already connected to grid power should not trigger modification with the addition of one or more electric controllers at the well site as this addition would not generate methane or VOC emissions.

We offer the following suggested for modification redline to §60.5365b(d)(1):

[75] Exemption of controllers on temporary equipment is consistent with state regulations in New Mexico and Colorado.

For the purposes of §60.5390b, in addition to the definition in §60.14, a modification occurs when the number of natural gas-driven pneumatic controllers at a site is increased by one or more.

We offer a suggested redline for reconstruction below in Comment 7.3.4.

To be clear, our support for the proposed provision as it relates to modification for natural gas-driven pneumatic controllers is contingent on this and the other clarifications requested throughout Comment 7.3. Absent these clarifications then we maintain our previous position submitted in our January 2022 comment letter (EPA-HQ-OAR-2021-0317-0808) and request EPA streamline applicability across various affected facilities by defining modification for the collection of natural gas-driven pneumatic controllers and pneumatic pumps like how EPA has defined modification for the collection of fugitive components at well sites and compressor stations. For central production facilities, modification should be based on an increase in designed throughput capacity with the addition of a storage vessel at the central production facility as we further elaborate in Comment 2.6.

7.3.4 Under NSPS OOOOb, reconstruction for natural gas-driven pneumatic controllers should not include replacement of a high-bleed natural gas-driven controller with a low-bleed or intermittent controller.

Many of our members have committed to the elimination of all remaining high-bleed controllers that may still be in use at existing locations. As we included in our January 31, 2022 comment based on data submitted to EPA through EPA's Greenhouse Gas Mandatory Reporting Program, data extracted for the 2020 calendar year clearly shows the breakdown of high-bleed natural gas-driven pneumatic controllers is only around 2% of total reported natural gas-driven pneumatic controllers across both the onshore production segment and onshore gathering and boosting segments. This indicates there are not many high-bleed devices left in operation at well sites, central production facilities, and compressor stations based on successful implementation of NSPS OOOO and NSPS OOOOa over the last decade.

Replacement of these last remaining high-bleed controllers with low-bleed or intermittent controllers would equate to an overall reduction in methane and VOC emissions and should not be included in the reconstruction provisions as this could disincentivize short term benefits of this type of replacement. With the implementation of EG OOOOc coinciding with proposed NSPS OOOOb, this clarification will only delay conversion to non-emitting without impacting current investment in equipment upgrades in the near term that provide immediate environmental benefit.

We offer the following suggested redline to §60.5365b(d)(2) to address these concerns and the clarification explained in Comment 7.3.3:

§60.5365b(d)(2): For the purposes of §60.5390b, owners and operators may choose to apply reconstruction as defined in §60.15(b) based on the fixed capital cost of the new natural gas-driven pneumatic controllers in accordance with paragraph (d)(2)(i) of this section, or the definition of reconstruction based on the number of existing natural gas-driven pneumatic controllers at the site in accordance with paragraph (d)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (d)(2)(i) or (ii); they do not need to apply both. If owners and operators choose to comply with paragraph (d)(2)(ii) they may demonstrate compliance with §60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven pneumatic controllers is replaced. That is, if

an owner or operator meets the definition of reconstruction through the "number of controllers" criterion in (d)(2)(ii), they will have shown that the "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility," as required in §60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of §60.15 that reference "fixed capital cost" through an initial showing that the number of controllers replaced exceeds 50 percent. For purposes of paragraphs (d)(2)(i) and (ii), "commenced" means that an owner or operator has undertaken a continuous program of natural gas-driven pneumatic controller replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven pneumatic controller replacement. Replacement of an individual natural gas-driven controller with a continuous bleed rate greater than 6 scfh with either a natural gas-driven controller with a continuous bleed rate less than 6 scfh or with an intermittent vent natural gas-driven pneumatic controller is excluded from this determination.

If the owner or operator applies the definition of reconstruction in §60.15(b)(1), reconstruction occurs when the fixed capital cost of the new natural gas-driven pneumatic controllers exceeds 50 percent of the fixed capital cost that would be required to replace all the natural gas-driven pneumatic controllers at the site. The "fixed capital cost of the new pneumatic controllers" includes the fixed capital cost of all natural gas-driven pneumatic controllers which are or will be replaced pursuant to all continuous programs of ~~component~~ natural gas-driven pneumatic controller replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].

If the owner or operator applies the definition of reconstruction based on the percentage of natural gas-driven pneumatic controllers replaced, reconstruction occurs when greater than 50 percent of the natural gas-driven pneumatic controllers at a site are replaced. The percentage includes all pneumatic controllers which are or will be replaced pursuant to all continuous programs of pneumatic controller replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].If an owner or operator determines reconstruction based on the percentage of natural gas-driven pneumatic controllers that are replaced, the owner or operator must also comply with §60.15(a), as well as the notification provisions specified in § 60.15(d), and the provisions of § 60.15(e) and (f) related to the Administrator's review.

7.3.5 Additional clarifications are required to the proposed requirements for reconstruction of pneumatic controllers.

In review of the proposed regulatory text provided for §60.5365b(d)(2), the following are elements of the proposed regulatory text require clarification.

- **It is unclear how the notifications from §60.15 apply to the reconstruction provision proposed in §60.5365b(d)(2).** The proposed language in §60.5365b(d)(2)(ii), suggests that reconstructed natural gas-driven pneumatic controllers would be subject to some of the requirements included in §60.15, which include 60-day notification and Administrator approval. This directly conflicts with information presented in Table 5 that states §60.15(d) does not apply to pneumatic controllers. We believe it was EPA's intent to not apply the additional notification and approval, given the number of facilities that will trigger reconstruction over time.

- **EPA includes reference to [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].** However, the regulatory text was not included in the Federal Register for neither the December 2022 Supplemental Proposal nor the November 2021 preamble description of requirements. It is unclear what date these provisions should be based. We believe this should be based on the December 2022 Supplemental Proposal.

7.4 Self-contained natural gas-driven controllers should follow the requirements for fugitive emission monitoring, not those for closed vent systems.

Self-contained natural gas-driven pneumatic controllers are configured to route emissions into the downstream piping, which is simply a hard piece of pipe with connectors or flanges. Given the simplicity and low potential for leaks or defects along the piping, EPA is correct in allowing OGI inspections, but we believe operators should follow the work practice for the fugitive emission monitoring requirements §60.5397b and not the NIE provisions as proposed.[76] EPA should also allow inspection of self-contained pneumatic controllers via the alternative screening techniques program, when applicable.

We also note that as proposed, the self-contained pneumatic controller requirements do not articulate repair or contain delay of repair provisions or timelines and we believe this was not EPA's intent. Given self-contained pneumatic controllers would more commonly occur on pressure control valves, the operator would likely need to shut-in the well or shutdown equipment in order to conduct any sort of repair (if any were found). We therefore request, at a minimum, that repair timelines in §60.5397b(h) and specifically the delay of repair provisions as described in §60.5397b(h)(3) apply to self-contained natural gas-driven pneumatic controllers.

As we mention in Comment 2.4, we encourage EPA to streamline how periodic monitoring in the proposed rules is conducted by following a consistent set of requirements including the frequency, repair schedule, and retention of associated records. This will provide clarity across all affected facilities at a site where monitoring is occurring.

7.5 For EG OOOOc, locations without access to electrical power should have the option to use low continuous bleed or intermittent bleed natural gas-driven pneumatic controllers with proper functioning confirmed through periodic monitoring until modification or reconstruction triggers NSPS OOOOb. At a minimum, EPA must consider an allowance for low production well sites and/or sites with a limited number of natural gas-driven controllers from retrofit within EG OOOOc.

Many existing well sites are low producing wells that could be close to end-of-life of their production cycle and may only contain a limited number of controllers. The complete retrofit of a low-producing facility is likely cost prohibitive based on well economics, which may result in many low production or stripper well sites shutting in production versus implementation of the collective costs associated with EG OOOOc. The BLM acknowledged this fact in their proposed Waste Prevention Rule by establishing an exemption of retrofit of pneumatic controllers based on facilities *"producing at least 120 Mcf of gas or 20 barrels of oil per month"* because *"it is unlikely that an*

[76] Should EPA continue to apply NIE as a numerical standard for self-contained pneumatic controllers, it could disincentivize conversion.

operator of a lease, unit, or CA producing only 120 Mcf of gas or 20 barrels of oil per month could re-direct the entirety of its revenues for 10 months towards paying for upgrading its pneumatic equipment."[77]

In our previous comment letter submitted January 2022, we supported retrofit for facilities with at least 15 controllers at a well site, central production facility, or compressor station. There have not been any drastic changes in actual costs to retrofit facilities or technical feasibility of implementing these types of retrofits in locations that do not have access to grid power. In fact, due to other similar regulations currently being implemented at the state level, the timeline for acquiring the necessary equipment is long due to supply chain limitations, and skilled labor is in short supply and high demand. We maintain our position that at these existing facilities any high-bleed natural gas-driven pneumatic controller should be replaced with a continuous low-bleed and/or with an intermittent controller and included within a company's fugitive emission monitoring program to monitor for proper functioning. The recordkeeping and reporting for these devices should follow requirements associated with fugitives and not have a separate set of requirements as currently proposed for sites in Alaska.

7.5.1 Spacing constraints at existing sites may cause technical infeasibility for converting to non-emitting controllers where grid power is not available.

Existing well site sites, central production facilities or compressor stations may have sizing constraints for the proper placement (due to safety and other permitting constraints) of instrument air control systems. Examples include an instrument air compressor that must sit outside of classified areas, generators, and/or or solar panels.

To retrofit a facility with an instrument air system, an engineer first verifies that adequate power is available and then applies for necessary state level permits, which takes approximately 60 days to acquire (if approved). On federal lands, this type of project would require reopening permits pursuant to National Environmental Policy Act, which is around a 12 to 18 month permitting process. On private lands, an operator may not be able to purchase additional land from the private owner.

During construction, an instrument air header and compressor skid must be added to the facility. The air compressors must sit outside of classified areas and therefore, some older reclaimed facilities may not have adequate space to add necessary equipment for the instrument air system because the air compressor must be placed outside of a safe radius from existing flares and other hydrocarbon-containing equipment (e.g. limitations due to electrical classifications). If accessible grid power is not available, a generator would have to be installed to power the air compressor, which would emit other pollutants.

7.5.2 Case Study Review for Land Required for Solar Retrofits

For existing medium and larger production sites and tank batteries, larger solar installations will be required to transition the sites to the proposed zero-emitting standard. As a case study, multiple sample sites throughout the country were evaluated to determine the space requirement for a solar installation that is equivalent to the energy of an instrument air system requiring 112 kilowatts (kW), which would be needed for large facilities not included in EPA's model plant analysis. Results are presented in Table 1.

[77] 87 FR 73606

This case study highlights that the land requirement for many sites is likely to be between 0.6 – 1.5 acres. Several key considerations to consider when installing solar panels at existing well sites that hinder the compatibility include:

- Site area footprints have already been agreed to and installing large arrays will require revisiting existing agreements to modify, a time consuming and costly process. Many jurisdictions, including the BLM, prefer smaller facility footprints.
- Site layout is already optimized for existing infrastructure to fit within a facility area.
- Adding in solar infrastructure of panels, wiring, battery, etc. could lead to complications and unnecessary safety hazards as batteries are introduced near hydrocarbons.
- Snowfall is prevalent in many of these regions and will reduce efficiency of the optimally angled panels. Vertically oriented arrays to prevent snowfall interference may not be appropriate in all circumstances unreasonable given the climate, wind, and remote nature of these sites.

Table 1. Case Study – Physical Land Requirement for Solar Installations Replacing Power Supply for 112 kW Generator

Site Location	Optimally Angled Panels[a]					Vertically Angled Panels[b]				
	Solar array estimate[c,d]	Array angle	Lowest Monthly Average Daily Peak Sun[e]	Count of Panels[f]	Solar Panel Acreage	Solar array estimate[c,d]	Array angle	Lowest Monthly Average Daily Peak Sun[e]	Count of Panels[f]	Solar Panel Acreage[g]
	kW	degrees	Hours			kW	degrees	Hours		
Carlsbad, New Mexico	620	28	5.1	2,067	0.7	1513	90	2.1	5,044	0.9
Midland, Texas	620	28	5.1	2,067	0.7	1558	90	2.0	5,193	0.9
Arnett, Oklahoma	735	30	4.3	2,452	0.8	1318	90	2.4	4,392	0.8
Denver, Colorado	719	31	4.4	2,396	0.8	1171	90	2.7	3,904	0.7
Pinedale, Wyoming	988	33	3.2	3,294	1.1	1091	90	2.9	3,635	0.6
Williston, North Dakota[h]	1318	35	2.4	4,392	1.5	1091	90	2.9	3,635	0.6

a. Optimally angled tilt (annual average) determined from National Renewable Energy Lab (NREL)'s PVWatts® Calculator; https://pvwatts.nrel.gov/pvwatts.php
b. Vertically angled systems were suggested by Clean Air Task Force at EPA-HQ-OAR-2021-0317-1451.
c. Size of installation determined from Omni calculator methodology required inputs of electricity consumption and solar hours per day to determine roof area of solar panels; https://www.omnicalculator.com/ecology/solar-panel
d. Using NREL's PVWatts calculator in conjunction with the Omni calculator, it was determined roof area was equal to ground area for simplification as, there was a <1% difference in annual kWH production.
e. Footprint Hero was used to determine the lowest monthly average daily peak sun-hours for each location for both panels at optimal angle and 90 degrees; https://footprinthero.com/peak-sun-hours-calculator
f. Number of panels based on average panel output of 300 watts and 15 square feet.
g. Acreage for vertically angled panels assumes panels would be stacked two panels high.
h. The high latitude of Williston, North Dakota has the lowest monthly average daily peak sun-hours when the solar array is optimally positioned. When vertically positioned the peak sun hours increases from 2.4 hours to 2.9 hours.

EPA should also consider the following in conjunction with results of this analysis:

- the cost of land acquisition;

- right-of-way and easement concerns/limitations;
- projection of further land-use change requirements for solar installations; and
- percent of further land use change required for solar installations on designated wetlands.

For existing locations without accessible grid power and where there is an ability to acquire additional land to use solar or natural gas generators, operators will not have the ability comply with the current proposal.

7.5.3 The incremental costs and benefits have not been adequately justified at existing locations.

Within the technical Support documentation, EPA does include a scenario for monitoring intermittent vent controllers. Based on EPA's own assumptions, this type of program can achieve 96.7% reductions in emissions (based on emission factors) for an overall site level control efficiency of 65% based on semi-annual OGI monitoring. Since many large facilities within the proposal will be required to conduct quarterly OGI, we anticipate this control efficiency to be even higher.

Furthermore, since all well sites, central production facilities and compressor stations will already be subject to fugitive emission monitoring at some frequency, the incremental cost to implement such a program for pneumatic controllers would be solely based on the additional recordkeeping and reporting that an operator would need to implement. The incremental costs and benefits associated with the zero-emitting provisions in comparison with this option to monitor controllers for proper functioning within a company's LDAR program, have not been adequately justified given the numerous technical infeasibility challenges communicated with implementing solar-powered electric controllers, spacing constraints at some existing facilities to install certain equipment, and other emission offsets that will stem from implementing other forms of power generation.

In EPA's analysis, the emission reductions from inspections of intermittent vents are based on emission rates assumed to be halfway between perfectly operating post-inspection controllers and the overall emission rate that includes both perfectly operating and malfunctioning controllers. This suggests that EPA has no data or understanding of how often intermittent bleed devices may not function properly, which is an important distinction given the expected costs of implementing these requirements at all locations as proposed under EG OOOOc.

7.6 EPA's cost-benefit analysis significantly underestimates the costs of implementing the proposed zero-emissions standard and overestimates the technical capabilities of solar and electric controllers.

In our January 31, 2022 comment letter, we provided detailed comments on the technical challenges that operators within U.S. are facing as they convert facilities to electricity, pilot solar powered instument air systems, and install natual gas-driven instrument air systems, which we incorporate again by reference.[78] As our members begin to plan, design and install zero-emitting penumatic controllers, it is clear that EPA has not adequately accounted for the costs of this proposal; especially with respct to retrofit of existing facilities. Total project costs, including equipment and labor, to retrofit a large gathering and boosting compressor station could exceed $1,000,000, which is substantially higher than EPA's projections.

[78] Comments found in EPA-HQ-OAR-2021-0317-0808

Upon review of the supplemental techncial Support Document, we have found EPA's cost-benefit analysis to significantly underestimate the cost (especially for retrofit of existing facilities) and overstate the techncial feasibility of making these retrofits as summarized below:

- EPA applied an emission factor for low-bleed pneumatic controllers, with a factor that by definition would be a high-bleed pneumatic controller. EPA has justified this update within the model plant by aligning the model plant to the proposed changes to Subpart W which is 6.8 scf/h. This emission factor is nearly a five-fold increase to the continuous low-bleed device emission factor; is greater than the threshold that had been applied to determine whether a device should be categorized as low-bleed or high-bleed; and a device with this level of emissions would not be allowed pursuant to NSPS OOOO or NSPS OOOOa. In our review of the proposed changes to Subpart W, we have asked EPA to provide the details of how this factor was determined as there is little documentation supporting this change. Regardless, it is an inappropriate factor for applying to a low-bleed device for NSPS OOOOb and EG OOOOc because an operator would not be able to install a continuous bleed natural gas-driven pneumatic controller with this manufacturer rating as it is considered a high-bleed pneumatic controller.
- EPA continues to describe application of solar-powered and electric controllers as being directly powered by the grid or solar technology in the model plant analysis. Operator experience is that sufficient air is required to properly control the pneumatic controllers, where an instrument air system (i.e., an air compressor and associated equipment and piping) is required in nearly all applications. Electric controllers lack the speed and performance of gas-powered or air-powered actuators and there are limited equipment configurations where electric controllers are technically feasible. Specifically, electric controllers have inadequate duty cycle ratings, and the torque ratings are typically too low for reliable performance. This significantly limits the utility of electrically actuated controllers. Even if they performed comparably to gas-powered actuators, electrically actuated controllers have a higher failure rate, especially for throttle service where the actuator is constantly adjusting based on process conditions instead of at a set point. The modelled analysis for these scenarios incorrectly estimates the cost-effectiveness of the proposed requirements.
- Application of solar technologies as it pertains to gathering and boosting compressor stations have not been adequately reviewed in EPA's model plant analysis. The production sector model plants are geared toward small well sites with only 4, 8 and 20 controllers analyzed. Larger facilities, i.e., those with more than 20 pneumatic controllers, are still not adequately accounted for.
    - The assumptions made by EPA in the model plant analysis severely underestimate the air compressor horsepower and instrument air needs for sites with more than 20 controllers. These smaller scale cost metrics will not linearly scale up with larger facilities where a new instrument air header and piping may need run across the larger Gathering & Booster station site and additional pipe supports or extended pipe rack may be necessary. In our January 31, 2022 comment letter we provided information on facilities using instrument air systems to power over 100 controllers.
- In a case study published by NREL[79], solar panel capital costs for off-grid production well sites are 2.7 times the cost of grid-connected well sites. This does not align with EPA assumptions.
- EPA's model plant assumptions do not adequately address costs associated with retrofit of existing facilities. We note that installation also necessitates the facility be temporarily shut in/shut down to

[79] https://www.nrel.gov/docs/fy20osti/76778.pdf

perform retrofits, which does not appear to be accounted for. Additional costs for retrofit at existing facilities that are missing from EPA's analysis include:

- Additional Land Requirement for Solar Panel Installation including acquisition costs.
- Site Preparation – For existing sites with tree lines, trimming may be required to maximize sun exposure. Additionally, for larger sites with more significant solar installations, foundation prep including concrete slabs was not considered.
- Solar panel maintenance and cleaning particulate accumulation.
- Permitting[80], Insurance and inclusion of battery boxes to house batteries in cold regions do not appear to be accounted for.
- Retrofits often require the existing methane pipe headers to remain in place as a source of fuel gas for on-site equipment (compressors, fired heaters, combustors/TO's, flares, etc.) and a new parallel air header needs to be run to a to all instruments. This can add significant costs depending on the site layout, if there is available space in the existing pipe rack and facility, or if additional pipe supports are also needed.

- While EPA recounts and summarizes the significant number of comments criticizing solar-powered controllers (87 FR 74764), the primary underlying basis to EPA's economic and technical feasibility analysis pertaining to the conversion of existing, natural gas-powered pneumatic control systems to zero-emission systems (e.g., electric, solar-powered) is based on a single report: *Zero Emission Technologies for Pneumatic Controllers in the USA initially published in August 2016 and then updated in November 2021 by Carbon Limits (on behalf of the Clean Air Task Force).*[81] The report and EPA's application of report costs within the model plant analysis have a number of flaws as we have described herein and as follows:

    - The 2021 Carbon Limits report authors primarily gathered information through interviews with three technology providers and two oil and gas companies, both production-oriented companies with limited application of the technologies. The report is based on installation of solar-powered instrument air systems at only 22 onshore production sites located in Alberta, Canada, Wyoming, Utah, and Peru. This is an extremely small sample size for a technology to be deemed technically feasible and cost effective for all U.S.-based oil and natural gas operations. In response to our comments Clean Air Task Force states "Some of the interviewed technology providers have installed these systems in over 400 well-sites." Again, this is a rather small population when considering the number of facilities that will be applicable to these rules.

    - The Carbon Limits report focuses on reliability of solar power systems in colder climates, not areas with limited sun exposure. The Canadian provinces cited in the study, Alberta and British Columbia, experience very large amounts of sunshine, supporting the idea that solar power

[80] https://www.solarpermitfees.org/SoCalPVFeeReport.pdf
[81] This basis was explicitly stated by EPA on page 46 of 173 to document Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review Supplemental Background Technical Support Document for the Proposed New Source Performance Standards (NSPS) and Emissions Guidelines (EG) 40 CFR Part 60, subpart OOOOb (NSPS), 40 CFR Part 60, subpart OOOOc (EG) (October 2022). EPA states, "The EPA notes that the primary basis for the costs used for the November 2021 analysis was not the White Paper, but rather a 2016 report by Carbon Limits, a consulting company with longstanding experience in supporting efficiency measures in the petroleum industry.The analysis was updated to reflect the information in the 2022 Carbon Limits report."

generation works best in areas with more sun. The study does not support reliability of solar powered systems in areas of limited sun exposure like West Virginia.

- Identified calculation errors and assumptions in the model plant analysis:
    - The EPA cost analysis appears to contain a calculation error in determining the annualized project cost; while a solar panel lifespan of 10 years was stated, a value of 15 years was used in the annualization, resulting in a 30% annual cost difference. See tabs in Supplemental TSD Ch 3 Pneumatic Controllers.xlsx tabs *BSER T&S new, BSER T&S existing, BSER Production new, and BSER Production existing.*
    - The EPA capital cost analysis for electric compressor retrofit at existing transmission, storage, and production sites does not consider applications greater than 10 hp (highest compressor and associated equipment (e.g., dryers, wet air receivers) is capped at $32,000). Larger-sized systems should be evaluated.
    - For electric powered compressed air systems, EPA applied an annualization period of 15 years. If the compressor equipment life is updated to reflect the 2021 Carbon Limits Study provided value of 6 years, this option is not economically feasible. It is unclear why EPA deviated from the Carbon Limits study for this assumption and not others.
    - Carbon Limits updated certain assumptions in the 2021 report release. For some assumptions, EPA continues to retain costs from the 2016 study, without explanation.
    - The Carbon Limits report assumed a greenfield installation factor of 1.5 times major equipment costs without any adequate explanation. Member experience suggests this is closer to 3 to4 times equipment costs.
    - EPA continues to assume at least 1 high-bleed pneumatic controller is present at existing source model plants, when the data submitted to EPA pursuant to 40 CFR Part 98, Subpart W suggests this is an incorrect assumption given the low number of high-bleed controllers still being reported. See Attachment C in EPA-HQ-OAR-2021-0317-0808.
    - The EPA deflated costs provided in 2021 dollars to 2019 dollars. As inflation continues to be elevated, this is an unrealistic assumption and not reflective of actual, or anticipated costs. Costs continue to increase across the economy. A more appropriate assumption would be to assume 2021 dollars are equal to 2019 dollars.

7.7 Recordkeeping and Reporting

As more surface site locations electrify pneumatic controllers over time, confirmation of compliance would be easily obtained through any inspection of a site that was connected to grid power, using solar panels or other instrument air system. Based on review of the issued reporting form (EPA-HQ-OAR-2021-0317-1536_content), it appears EPA's intent was to streamline recordkeeping and reporting to only natural gas-driven controllers, which are the affected facility. However, the language proposed within NSPS OOOOb per §60.5420b(c)(6)(i) and EG OOOOc is unclear in this regard. EPA should not require recordkeeping or reporting on pneumatic controllers that are not natural gas-driven.

8.0 Natural Gas-Driven Pneumatic Pumps

8.1 The applicability date for pneumatic pumps under NSPS OOOOb should be the date of the Supplemental Proposal.

While we maintain that the applicability of NSPS OOOOb should apply based on the December 2022 Supplemental Proposal, which included regulatory text for all affected facilities, this is particularly true for natural gas-driven pneumatic pumps. In the preamble (87 FR 74770)[82], EPA even acknowledges the proposed rule varies significantly from what was described in the November 2021 description for pneumatic pumps:

> ***The proposed NSPS OOOOb requirements in this Supplemental Proposal differ from the November 2021 proposal in several ways, starting with the affected facility definition.*** *As noted above, in the November 2021 proposal, a pneumatic pump affected facility was defined as each natural gas-driven pneumatic pump. In this Supplemental Proposal, a pneumatic pump affected facility is defined as the collection of all natural gas-driven pneumatic pumps at a site.*
>
> ***…****Specifically, the EPA is proposing that pneumatic pumps not driven by natural gas be used.* ***This is a significant change from the November 2021 proposal,*** *which would have required that emissions from pneumatic pump affected facilities be routed to control or to a process, but only if an existing control or process was on site****. (emphasis added)***

In these statements EPA acknowledges that not only did the affected facility definition expand to the collection of pumps at a site, but it also expanded to include piston pumps, which have not historically been regulated in NSPS OOOOa. Additionally, the proposed control options under NSPS OOOOb are completely unexpected and the hierarchy of options proposed would not have been a logical expectation based on the description in November 2021 proposal description. Specifically, operators have had no way of knowing:

1) Piston pumps would be affected facilities under §60.5365b(h).

2) The collection of both piston pump and diaphragm pumps would constitute an affected facility under §60.5365b(h).

3) The control standard would require a zero emissions control or a suite of ongoing certifications to demonstrate feasibility or infeasibility in §60.5393b.

4) Modification and reconstruction have never applied to such small ancillary equipment such as a single piston pump or diaphragm pump.

Therefore, the applicability date for pneumatic pumps under NSPS OOOOb should be the date of Supplemental Proposal.

[82] Federal Register / Vol. 87, No. 233 / Tuesday, December 6, 2022 / Proposed Rules

8.2 Under NSPS OOOOb, we support the use of non-emitting pneumatic pumps for newly constructed well sites, tank batteries, and compressor stations, but we do not support the hierarchy of options proposed and inclusion of additional certification statements. The standard should be technology neutral similar to the pnuematic controller requirements.

The control options proposed for natural gas-driven pneumatic pumps are the same as those proposed to control natural gas-driven pneumatic controllers, yet the EPA is requiring additional technical demonstrations for pneumatic pumps that are not required for pneumatic controllers. We believe the requirements for natural gas-driven pneumatic pumps should be similar to those proposed for pneumatic controllers and the allowance for routing emissions to a control device which is allowed for pumps be extended to controllers (without any additional technical demonstration).

Furthermore, the hierarchal structure as proposed does not make logical sense as routing emissions to process, which has been a long-standing compliance option under the NSPS, is placed at a lower tier than that of implementing instrument air systems using solar or natural gas. As provided in Comment 12.9, the additional certifications associated with this hierarchy should be removed. The CAA already has provisions for knowing criminal violations related to false statements, which includes reference to false material statement, representation, or certification in/omits material information from/alters, conceals or fails to file or maintain a document filed or required to be maintained under the CAA.

8.3 Under NSPS OOOOb, EPA must clarify that modification and reconstruction is limited to natural gas-driven pneumatic pumps.

Throughout the proposed NSPS OOOOb and EG OOOOc, EPA uses the terms ‘natural gas-driven pneumatic pump’ and ‘pneumatic pump’ interchangeably. EPA must be clear that the affected facility and other applicability language is specific to natural gas-driven pneumatic pumps. This clarification is especially important as these terms are used within the description for modification and reconstruction. For example, an existing well site that is already connected to grid power should not trigger modification with the addition of one or more electric pumps as this addition would not generate methane or VOC emissions.

We offer the following suggested for modification redline to §60.5365b(h)(1):

> *For the purposes of §60.5393b, in addition to the definition in §60.14, a modification occurs when the number of natural gas-driven pneumatic pumps at a site is increased by one or more.*

We offer the following suggested for modification redline to §60.5365b(h)(2):

> *For the purposes of §60.5390b, owners and operators may choose to apply reconstruction as defined in §60.15(b) based on the fixed capital cost of the new natural gas-driven pneumatic pumps in accordance with paragraph (h)(2)(i) of this section, or the definition of reconstruction based on the number of natural gas-driven pneumatic pumps at the site in accordance with paragraph (h)(2)(ii) of this section. Owners and operators may choose which definition of reconstruction to apply and whether to comply with paragraph (h)(2)(i) or (ii); they do not need to apply both. If owners and operators choose to comply with paragraph (h)(2)(ii) they may demonstrate compliance with §60.15(b)(1) by showing that more than 50 percent of the number of natural gas-driven pneumatic pumps is replaced. That is, if an owner or operator meets the definition of reconstruction through the "number of natural gas-driven pneumatic pumps"*

criterion in (h)(2)(ii), they will have shown that the "fixed capital cost of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable entirely new facility," as required in §60.15(b)(1). Therefore, an owner or operator may comply with the remaining provisions of §60.15 that reference "fixed capital cost" through an initial showing that the number of natural gas-driven pneumatic pumps replaced exceeds 50 percent. For purposes of paragraphs (h)(2)(i) and (ii), "commenced" means that an owner or operator has undertaken a continuous program of ~~component~~ natural gas-driven pneumatic pump replacement or that an owner or operator has entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of natural gas-driven pneumatic pump replacement.

(i) If the owner or operator applies the definition of reconstruction in §60.15, reconstruction occurs when the fixed capital cost of the new natural gas-driven pneumatic pumps exceeds 50 percent of the fixed capital cost that would be required to replace all the pneumatic pumps at the site. The "fixed capital cost of the new pneumatic pumps" includes the fixed capital cost of all natural gas-driven pneumatic pumps which are or will be replaced pursuant to all continuous programs of ~~component~~ natural gas-driven pneumatic pump replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].

(ii) If the owner or operator applies the definition of reconstruction based on the percentage of natural gas-driven pneumatic pumps replaced, reconstruction occurs when greater than 50 percent of the pneumatic pumps at a site are replaced. The percentage includes all natural gas-driven pneumatic pumps which are or will be replaced pursuant to all continuous programs of ~~component~~ natural gas-driven pneumatic pump replacement which are commenced within any 2-year rolling period following [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER]. If an owner or operator determines reconstruction based on the percentage of natural gas-driven pneumatic pumps that are replaced, the owner or operator must comply with §60.15(a), as well as the notification provisions specified in § 60.15(d), and the provisions of § 60.15(e) and (f) related to the Administrator's review also apply.

8.3.1 Additional clarifications are required for the proposed requirements for reconstruction of pneumatic pumps.

In review of the proposed regulatory text provided for §60.5365b(h)(2), the following elements of the proposed regulatory text require clarification:

- **It is unclear how the notifications from §60.15 apply to the reconstruction provision proposed.** Similar to natural gas-driven pneumatic controllers, the proposed language in §60.5365b(d)(2)(ii) suggests that reconstructed natural gas-driven pneumatic pumps would be subject to some of the requirements included in §60.15, which include 60-day notification and Administrator approval. This directly conflicts with information presented in Table 5 that states §60.15(d) does not apply to pneumatic pumps. We believe it was EPA's intent to not apply the additional notification and approval, given the number of facilities that will trigger reconstruction over time.

- **EPA includes reference to [INSERT DATE OF PUBLICATION OF THE PROPOSED RULE IN THE FEDERAL REGISTER].** However, the regulatory text was not included in the Federal Register for neither the December 2022 proposal nor the November 2021 preamble description of requirements. It is unclear what date these provisions should be based. We believe this should be based on the December 2022 proposal.

8.4 Suggested clarifications to certain proposed definitions related to pneumatic pumps in NSPS OOOOb and EG OOOOc.

While EPA expanded the applicability to include piston pumps, EPA did not include a definition for what a piston pump is or is not beyond the definition for natural gas diaphragm pump currently provided. Without this additional definition we request the following technical clarification as it applies to lean glycol circulation pumps. We do not believe it was EPA's intent to include these within the new zero-emitting provisions and historically EPA made it clear that this was not their intent to include these under NSPS OOOOa.

> ***Natural gas-driven diaphragm pump*** *means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump for purposes of this subpart. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a ~~diaphragm~~ pneumatic pump.*

8.5 The provisions included §60.5365b(h)(3) should also reference piston pumps.

There are many scenarios where portable pneumatic pumps are used by industry for infrequent and temporary operations, such as pumping out a tank or a sump. We support EPA's retention of the provisions proposed in §60.5365b(h)(3) as these pumps will, by their very nature, result in very low and intermittent emissions. In the model plant analysis, the emissions for a single natural gas-driven piston pump is only 0.11 tpy VOC and 0.38 tpy methane. Temporarily used piston pumps would emit even less, which is why they have historically been exempt from the control standards. Such an exemption would be analogous to what also already been granted for temporary natural gas-driven diaphragm pneumatic pumps, and we believe it was EPA's intent to also include piston pumps in this provision.

We offer the following suggested redline to §60.5365b(h)(3):

> *A single natural gas-driven diaphragm pump or piston pump that is in operation less than 90 days per calendar year is not part of an affected facility under this subpart provided the owner/operator keeps records of the days of operation each calendar year in accordance with §60.5420b(c)(15)(i) and submits such records to the EPA Administrator (or delegated enforcement authority) upon request. For the purposes of this section, any period of operation during a calendar day counts toward the 90-calendar day threshold.*

8.6 Natural gas-driven pneumatic pumps in compliance with NSPS OOOOa

NSPS OOOOa requires certain diaphragm natural gas driven pumps to be routed to a control device or process. As such, these pumps are already controlled by at least 95%. EPA has not adequately considered or accounted for how to handle these existing controlled pneumatic pumps within the proposed rules. Specifically, these pumps should meet the requirements of EG OOOOc by continuing to comply with NSPS OOOOa. These pumps should also be excluded from modification and reconstruction under NSPS OOOOa.

8.7 EPA's Model Plant Analysis for Conversion to Electric, Solar or Instrument Air Pumps

EPA assumptions for converting pneumatic pumps to zero-emitting has a distinctly separate set of cost assumptions from the pneumatic controllers even though the same technologies are being proposed for use. While EPA relied on costs from the 2016 and 2021 Carbon Limits report for pneumatic controllers, EPA uses different costs and assumptions as it pertains to converting to electric (assumed to be grid power) and solar pumps, which are not well documented and appear based on old information dating back to 2012. The EPA's economic feasibility analysis for pneumatic pumps presented in file "Supplemental TSD Ch 4 Pneumatic Pump.xlsx" are also only adjusted to 2019 USD from 2012 dollars. Thus, values presented are underestimated by at least 14%.[83]

9.0 Well Liquids Unloading Operations

As we communicated to EPA in our January 31, 2022 letter[84], well liquids unloading is a complex topic that has historically been difficult to address from a regulatory perspective because there are numerous misconceptions about why and how this activity is conducted. While we support EPA's inclusion of well liquid unloading operations as an affected facility, the regulation should be based solely on the work practice standard outlined in §60.5376b(c)(2) and (d) and should not include a zero-emission limit as provided in §60.5376b(b). To this end, the recordkeeping and reporting requirements must be amended to be a workable framework for operators to assure compliance including removal of the certification statement by an engineer in every instance that venting may occur.

Lastly, the applicability for liquid unloading operations must be designated as the date of the Supplemental Proposal as the recordkeeping requirements were not explicitly known for each event that ocurred prior to the publication. Much of the recordkeeping elements proposed in the December 2022 proposal, including the certification statement by engineer, was not anticipated based on the descriptions in the November 2021 proposal.

9.1 Well liquid unloading operations should be subject to work practice standards and not held to a zero-emission limit.

API supports the proposed alternative measures outlined in §60.5376b(c)(2) and (d), which provide a clear and rational work practice standard based on Best Management Practices (BMPs) that achieve the intent to reduce

[83] https://www.usinflationcalculator.com/
[84] EPA-HQ-OAR-2021-0317-0808

emissions from liquid unloading of gas wells. These provisions should be considered BSER and should not be considered an exception to the standard as currently proposed in §60.5376b(c).

We appreciate EPA's recognition that solely imposing an absolute requirement would constitute an unwarranted prohibition on necessary operations that in many situations could severely halt natural gas production. For some situations, a certain unloading technique may reduce emissions, but the same option might increase emissions if applied on another well with differing characteristics. The work practice standards proposed in §60.5376b(d) allow operators the flexibility needed to minimize emissions from well liquid unloading, while allowing for unexpected situations or outcomes that may occur during the unloading operation that might result in a minimal amount of emissions to be vented.

To be clear, while we support the work practice provisions in §60.5376b(c)(2) and (d), we do not support the provisions proposed in §60.5376b(b) establishing a zero-emission limit on liquid unloading operations as this limit creates undue burden of compliance when EPA has acknowledged it is known that not every liquid unloading operation can technically or safely meet the zero-emission limit. This undue burden is compounded when considering the logistical and practical implementation of the associated recordkeeping, reporting and certification statements also proposed. See also Comment 12.9.

9.2 Additional clarification to the proposed definition of liquids unloading is warranted.

As we previously commented in our January 31, 2022 letter, other well maintenance and workover activities may occur on a well that are distinctly different, require separate specialized equipment and operation, and are reported differently in federal and state greenhouse gas inventories from well liquids unloading. EPA must explicitly provide clarification to address these distinctions, within the definition for "liquids unloading" so not to confuse other activities that might occur at a well with the liquids unloading operation provisions as proposed.

Our suggested clarification to the definition of liquids unloading under §60.5430b and §60.5430c is as follows:

> *Liquids unloading means the unloading of liquids that have accumulated over time in gas wells, which are impeding or halting production. Routine well maintenance activities, including workovers, screenouts, coil tubing cleanouts, or any other activity that requires a rig or other machinery are not considered liquids unloading.*

9.3 The recordkeeping and reporting for liquids unloading operations must be simplified into a manageable framework for operators and streamlined for liquid unloading operations that vent to atmosphere.

The information proposed by EPA within §60.5420b and §60.5420c for the recordkeeping and reporting as it pertains to liquid unloading operations is focused on an operator tracking and certifying techniques and less focused on allowing an operator to perform the necessary procedures to unload liquids accumulated within the wellbore and maintain natural gas production with as minimal emissions as possible. To address this shortfall, we suggest EPA define the data operators should track per unloading operation and remove all superfluous records that generate additional burden for the operator and EPA without added environmental benefit. These suggestions assume that liquid unloading operations are to be conducted using a work practice standard according to our suggestion in Comment 9.1.

The current proposed recordkeeping requirements do not offer a reasonable framework for operators to maintain compliance assurance. In fact, EPA has included a certification by professional engineer for every instance a well unloading operation vents emissions to atmosphere in §60.5420b(c)(2)(ii)(B) and §60.5420b(b)(3)(ii)(B) based on the proposed zero emissions limit standard. This may not be known to an operator until the liquid operation is taking place based on a variety of parameters. For context, a single well affected facility may undergo multiple liquid unloading operations in a single compliance period. For example, one well may necessitate an unloading schedule of four times in a year. Based on best management procedures, three (3) of these events may occur with zero emissions, while one (1) of the events might vent to atmosphere for a short duration using the same technique. The justification provisions in §60.5420b(c)(2)(ii)(B) are untenable when the same technique used on a well may resulted in zero emissions during some liquid operations, but not during all liquid unloading operations in the same compliance period. The fact is that in some instances a well liquid unloading operation may need to vent emissions for short duration, sometimes a little as 30 minutes, to safely perform the liquid unloading operation. We therefore request:

1) EPA remove the additional engineering certification statements under the guise of technical demonstrations. These additional certifications would be unnecessary if the standard followed a work practice procedure (see Comment 9.1).

2) Limit recordkeeping and reporting to liquid unloading operations that result in emissions only. This would reduce the administrative burden for thousands of liquid unloading operation events. This is also consistent with how both Colorado and New Mexico have organized recordkeeping and reporting for their state regulations.

   Our suggestions to streamline and simplify the recordkeeping and reporting for liquid unloading operations is as follows:

   > *For each gas well affected facility that conducts liquids unloading operations during the reporting period that resulted in emissions vented to the atmosphere:*
   >
   > - *US Well ID*
   > - *The number of liquids unloading events during the year that resulted in emissions.*
   > - *The date and time of each liquid unloading operation where venting occurred.*
   > - *The duration of venting in hours.*
   > - *Reason venting occurred*

Additional recordkeeping for liquid unloading operations should include:

> *Documentation of your best management practice plan developed under paragraph §60.5376b(d). You may update your best management practice plan to include additional steps which meet the criteria in §60.5376b(d).*

10.0 Compressors

API endorses the comments being submitted by GPA Midstream Association as it pertains to reciprocating and centrifugal compressors and provides the following additional comments.

10.1 Reciprocating and Centrifugal Compressors should be subject to a work practice standards with clear repair and delay of repair provisons instead of an emission standard.

Within Section IV.I.of the preamble (87 FR 74796), the EPA acknowledges *"over time, during operation of the compressor, the rings become worn, and the packaging system needs to be replaced to prevent excessive leaking from the compression cylinder."* EPA also provides its rationale for the proposed level of excessive leaking (87 FR 747996) as "*the 2 scfm flow rate threshold was established based on manufacturer guidelines indicating that a flow rate of 2 scfm or greater was considered indicative of rod packing failure."* In summary, the EPA anticipates emissions from rod packings over time even from reciprocating compressors that are properly operated and maintained.

Yet, at the same time, EPA proposes to establish the 2 scfm flowrate as a not-to-exceed standard of performance, such that a violation occurs if flow rate exceeds that value (87 FR 74797). In doing so, EPA fundamentally misconstrues the manufacturers recommendations. In practice, exceeding a manufacturer-recommended flow rate is an indication that a repair should be made. Exceeding that rate does not necessarily compromise operability of the unit and, in fact, the values are selected to allow continued operation for the period necessary to arrange for needed repairs to be made. EPA without explanation proposes to transform what in practice constitutes an action level into a regulatory cap that cannot be exceeded without the prospect of incurring a violation. EPA's proposal is at odds with the facts and is an unreasonable reinterpretation of standard maintenance practices.

Therefore, if EPA is intent on setting a numeric standard of performance, the value must be well above the 2 scfm that EPA believes to be the standard manufacturer recommendations. The value must accommodate operations for a reasonable and potentially significant period of time that may be needed to accomplish needed repairs. If EPA takes this path, a reproposal is necessary so that we can know the newly proposed value, understand EPA's rationale, and have an opportunity to submit comments on the record. Alternatively, we believe that the flowrate can be established as a work practice that would trigger a repair obligation rather than constitute a numeric emissions limitation. While it is true that flow can be measured here, it is not technically or economically practicable to install measurement systems that would assure complliance with a numeric emissions limitation. See CAA § 111(h)(2)(B).

10.2 Clarification is required for compressors with multiple cylinders or seals.

In the November 2021 preamble (86 FR 63216), EPA described the rod packing requirements as follows:

> *"We are proposing that BSER is to replace the rod packing when, based on annual flow rate measurements, there are indications that the rod packing is beginning to wear to the point where there is an increased rate of natural gas escaping around the packing to unacceptable levels. We are proposing that if annual flow rate monitoring indicates a flow rate for any individual cylinder as exceeding 2 scfm, an owner or operator would be required to replace the rod packing."*

In looking at documentation for the dry seal proposed requirements, the Natural Gas Star[85] report where this value was seemingly derived, it is stated, "*During normal operation, dry seals leak at a rate of 0.5 to 3 scfm across each seal (1-6 scfm for a two seal system), depending on the size of the seal and operating pressure…. An example of one type of tandem seal with leak rates ranging between 0.5 to 3 scfm for 1.5 to 10 inch compressor shafts, for compressors operating at 580 to 1,300 psig pressure.*"

In the proposed text provided in §60.5380b or §60.5385b(a), the distinction that the limits are per cylinder or seal is unclear. It would be impratcical for a compressor with multiple cyclinders (reciprocating) or seals (centrifugal) to operate the same as compressor with only a single cyclinder or seal. As the Natural Gas star report documents, it is also impractical to expect the same level of emissions from dry seals for various sized units.

Therefore, EPA must clarify that the emission threshold designated is by cylinder or throw (reciprocating) and per seal (centrifugal). We note that the following suggested redlines for NSPS OOOOb and EG OOOOc are consistent with §95668 (c)(4)(D) of the 2017 California's GHG Emissions Regulations, which this proposed standard was based:

> *§60.5385b(a): The volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm) per individual cylinder. If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.*
>
> *§60.5393c(a): The volumetric flow rate, measured in accordance with paragraphs (b) of this section, must not exceed 2 standard cubic feet per minute (scfm) per individual cylinder. If the individual cylinders are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual cylinders multiplied by 2 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(1) and (2) of this section.*
>
> *§60.5380b(a)(4)(i): The volumetric flow rate must not exceed 3 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm. You must conduct measurements of the volumetric flow rate in accordance with the schedule specified in paragraphs (a)(4)(ii) and (iii) of this section and determine the volumetric flow rate in accordance with paragraph (a)(5) of this section.*
>
> *§60.5392c(a)(1): You must conduct volumetric flow rate measurements from each centrifugal compressor wet and dry seal vent using the methods specified in paragraph (a)(2) of this section and in accordance with the schedule specified in paragraphs (a)(1)(i) and (ii) of this section. The volumetric flow rate, measured in accordance with paragraph (a)(2) of this section, must not exceed 3 standard cubic feet per minute (scfm) per seal. If the individual seals are manifolded to a single open-ended vent line, the volumetric flow rate must not exceed the sum of the individual seals multiplied by 3 scfm.*

[85] https://19january2021snapshot.epa.gov/sites/static/files/2016-06/documents/ll_wetseals.pdf

10.3 Conducting annual measurements on temporary compressors is logistically impractical and temporary compressors should be exempt from §60.5365b(b) and (c)(b).

Temporary compressors should be exempt from the monitoring requirments as it would be infeasible to conduct monitoring on a compresor that will be removed from a site after less than a year. Equipment that is intended for temporary use and is not a stantionary source should not not be subject to either NSPS OOOOb and EG OOOOc. API requests EPA make the following clarifications to address this concern:

> *§60.5365b(b): Each centrifugal compressor affected facility, which is a single centrifugal compressor. A centrifugal compressor located at a well site is not an affected facility under this subpart. A centrifugal compressor located at a centralized production facility is an affected facility under this subpart. A centrifugal compressor that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 12 consecutive months is not an affected facility under this subpart.*

> *§60.5365b(c): Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site is not an affected facility under this subpart. A reciprocating compressor located at a centralized production facility is an affected facility under this subpart. A reciprocating compressor that is skid mounted or permanently attached to something that is mobile (such as trucks, railcars, barges, or ships) and intended to be located at a site for less than 12 consecutive months is not an affected facility under this subpart.*

10.4 Reciprocating Compressors

While API supports certain aspects of the Supplemental Proposal for reciprocating compressors, addiitonal clarifications must be made. The following amendments, in addition to the items outlined above and in comments submitted by GPA Midstream Association, would alleviate some of the significant technical cocnerns our members have with the proposed requirements.

- **Emissions from reciprocating rod packing vents that are routed to a process or flare should be considered an adequate alternative in reducing emissions.** EPA should continue to allow an option for rod packing vents to be routed to a control device for new, modified and existing facilities. The incremental benefit achieved between monitoring and subsequent repair (if applicable) versus capturing the vent to control device that achieves 95% destruction efficiency has not been substantiated by EPA within their cost benefit analysis. This is especially true for any compressor that already is designed and configured to route rod packing to a flare or other combustion device.

- **EPA should provide additional flexibility for addressing rod packing leaks by allowing operators to forgo annual emission measurements and replace rod packing annually.** Given the sheer number of compressors that will apply to NSPS OOOOb and EG OOOOc, EPA should provide flexibility by allowing operators the option to change out rod packing annually or 8760 hours (whichever comes first), which is similar in approach but more frequent than the current requirements in NSPS OOOO and OOOOa, or to perform the newly proposed annual monitoring and replacement of rod packing if emissions exceed to specific threshold as identified.

- **Repair parameters were omitted from the proposed regulatory text.** The EPA states their intent to define some repair parameters for reciprocating compressors in the preamble (87 FR 74798):

  > *"The proposed NSPS OOOOb regulatory text also specifies that flow rate monitoring be conducted in operating or standby pressurized mode, and "repair" and "delay of repair" schedules, in addition to other clarifying requirements. The EPA is proposing to require conducting flow rate measurements during operating or standby pressurized mode because the measured emissions would be representative of actual emissions during operations. Repair schedules are proposed to require repair of equipment in a timely manner to mitigate emissions. Delay of repair would be allowed when owners and operators required more time to repair equipment based on scenarios beyond the owner or operator's control (e.g., issues with availability of equipment or where repair necessitates a compressor shutdown when redundancy of compressors is not available)."*

  However, the repair and delay of repair schedules could not be located in the proposed regulatory text. As stated in Comment 10.1, the EPA should establish a monitoring schedule for reciprocating compressors with reasonable repair times. Further, allowances should be incorporated to address situations that delay repairs, appropriately.

  California regulations governing rod packing emissions, upon which these proposed regulations are based, require repair within 30 calendar days from the date of the initial emission flow rate measurement. Furthermore, repair of a compressor typically cannot be performed while the compressor is in service, and some situations may arise that warrant delay of repair. We therefore request EPA amend the provisions in §60.5380b and §60.5385b to accommodate a work practice standard that includes clear provisions for repair or replacement and delay of repair or replacement that is consistent with §60.5397b(h)(3).

10.5 Centrifigal Compressors

10.5.1 Clarification is requested to the definition of centrifugal compressor.

Within the definition "centrifugal compressor" in §60.5430b and §60.5430c, EPA describes the compressor as "*discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers."* The phrasing of "significantly higher-pressure" should be further delineated to eliminate ambiguity. If left undefined the regulated operator does not have a clear understanding of what is affected and what is not affected.

The definition of centrifugal compressor as it was used in the initial NSPS OOOO rulemaking only affected wet-seal centrifugal compressors, which includes a relatively small population of affected facilities that were generally considered to discharge significantly higher-pressure natural gas. With the expansion of the NSPS OOOOb and EG OOOOc to also include dry seal compressors, which are more widely utilized, additional clarity is warranted.

In the oil and natural gas industry, compressors that boost natural gas pressures are normally designed to discharge natural gas greater than 300 pounds per square inch differential (psid). The original intent of EPA including this language was to exclude smaller compressors with low differential pressure (e.g., process compressors, vapor recovery units, and other low pressure service units). With this consideration, API recommends that EPA update §60.5430b to include a definition of significantly higher-pressure and includes the following language:

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher-pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart. For the purposes of §60.5380b, significantly higher-pressure means having a design pressure differential greater than 300 pounds per square inch differential (psid).

10.5.2 The emission limit for dry seal compressors should properly account for compressor size.

The origin of and basis for the proposed three (3) scfm limit for dry seal compressors is not provided within the EPA docket and associated references. API suspects that the genesis of this number did not consider variable compressor sizes, resulting in a low value for the standard that is not representative of all operations. In Section IV.G.1.b.iii of the Federal Register, the origin of this value is as follows: *"The 3 scfm volumetric flow rate emission limit is the same monitoring limit included in §95668(d)(4-9), California's Regulations*[86] *for Greenhouse Gas Emission Standards for Crude Oil and Natural Gas Facilities. California developed the 3 scfm emission standard because this was the equivalent to an average dry seal emission rate*[87]*."* Research into the underlying sources of the CARB regulation does not yield supporting information for the development of the 3 scfm standard. EPA should supplement the docket with information to support why this value is representative of the population of dry seal compressors across the nation (taking into consideration compressor size variability).

Larger compressors usually have larger shaft diameters, higher operating speeds, and greater operating pressures. These three variables all contribute factors to the amount of gas that might ultimately slip through the seals. The combination of these three factors will usually yield higher leak rates from seals as measured on a volumetric basis, thus larger compressors will have a higher baseline for normal operations.

Based on data submitted to the EPA pursuant to 40 CFR Part 98, Subpart W for the 2021 calendar year, dry seal compressor driver power output ranged between 5 – 42,000 horsepower and for wet seals the compressor driver power output ranged between 40 – 53,665 horsepower.[88] We do not believe compressors associated with the higher end of this range should be expected to operate the same as compressors closer to the lower end of this range. Table 2provides more details on our short analysis showing variable sizes of both dry and wet seal compressors as reference.

[86] https://ww2.arb.ca.gov/sites/default/files/2020-03/2017 Final Reg Orders GHG Emission Standards.pdf
[87] https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2016/oilandgas2016/oilgasisor.pdf, page 100.
[88] Information was extracted from EPA's Envirofacts database using the GHG query builder: https://enviro.epa.gov/query-builder/ghg.

Table 2. Variation in Compressor Driver Output as Reported under EPA's Greenhouse Gas Reporting Program for Calendar Year 2021

Compressor Horsepower Driver Details as reported to EPA for Calendar Year 2021	Count of Compressors in Dataset	Compressor driver power output (Horsepower)		
		Average	Minimum	Maximum
Dry Seals				
Onshore natural gas processing	310	6,427	5	38,000
Onshore natural gas transmission compression	812	14,431	144	42,000
Underground natural gas storage	19	9,817	5,700	15,280
Wet Seals				
Onshore natural gas processing	199	9,426	40	53,665
Onshore natural gas transmission compression	345	5,027	990	30,000
Underground natural gas storage	22	3,910	1,275	9,800

10.5.3 Additional clarification is needed regarding the volumetric flow.

Both wet seal and dry seal systems often use an inert gas, such as nitrogen, for system blankets at positive pressure. That nitrogen vents through the same vent as the seal gas. So measured total vent rates may be overestimating the amount of methane or VOC being vented to atmosphere. Actual vent rates of methane and VOC could be under the standard, but the total volumetric flow could be over due to the nitrogen blanket. EPA should make clear that the standard could be interpreted as either total volumetric flow or methane and VOC flow depending on which method of monitoring is employed.

EPA should also expand the volumetric flow measurement options to allow for alternative ways to obtain the methane and VOC flow:

- Use of thermal mass meter or ultrasonic meter readings in conjunction with gas composition samples to calculate methane and VOC flow, or
- Flow balance equations (i.e., if the amount of inert gas into the system is metered, then that volume could be subtracted from the total flow measurement, thus yielding the methane and VOC only flow.)

10.5.4 The wet seal centrifugal compressor requirements must be clarified between NSPS OOOOb and EG OOOOc.

It is unclear why the standards between NSPS OOOOb and EG OOOOc for centrifugal compressor standards are different:

- NSPS OOOOb – Dry seal compressors and "self-contained wet seal compressors" can only comply with volumetric standard. All other wet seal compressors can only comply with the 95% capture and control requirement.
- EG OOOOc – Any wet seal compressor can either comply with volumetric standard or reduce emissions by 95% through a control standard.

The implications of the NSPS OOOOb regulations seem to be that the 3 scfm volumetric standard is equivalent to the 95% capture and control requirement. If this is the case, then it stands to reason that all centrifugal compressors should be able to choose to comply with either the volumetric standard or the 95% capture and control practice.

If owners of centrifugal compressors had the option to comply with either standard, it obviates the need for a specially defined class of compressors: "Self-contained wet seal compressors." Removing this definition from the rule would result in a more simple and straightforward understanding of the rule requirements. API proposes the NSPS OOOOb standards mimic the EG OOOOc standards.

10.5.5 The proposed requirements for Wet Seal Centrifugal Compressors do not consider our previous comments regarding the unique equipment design in the Alaskan North Slope.

On the Alaska North Slope (ANS) there is not a market for natural gas sales. Most of the gas that is produced with the oil is separated and either used as a fuel or is compressed (using large wet seal compressors) to be reinjected back down hole for gas lift or enhanced oil recovery. The wet seal compressors on the ANS were installed from the mid-1970s to the mid-1980s, when the oil fields there began to be produced.

Wet seal centrifugal compressors located on the ANS were originally designed and installed with a seal oil degassing system that captures most of the gas by volume then routes that gas to a flare, as described in our January 31, 2022 comment letter[89]. The ANS system design is simple. Rather than routing the sour seal oil directly to a degassing drum/tank (which vents to atmosphere), the sour seal oil is first routed to the sour seal oil traps. In these traps, most of the gas breaks out of the oil while remaining at a high enough pressure that it can enter the low-pressure flare header line. The gas that breaks out in these traps is routed to the flare, not vented. The sour seal oil is only then sent to the degassing drum / tank, where any remaining entrained gas breaks out and is vented to atmosphere. In 2010, EPA's Natural Gas Star[90,91] program, in conjunction with BP, conducted an analysis of this wet seal degassing system design on the ANS at the Central Compressor Station. This analysis concluded that the sour seal oil degassing design employed on the ANS has greater than 99% emission control by volume. This same study is also cited by the CARB regulations references. It would stand to reason that this system of gas capture and control should be allowable to use the volumetric standard.

In summary, wet seal compressors with the sour seal oil traps in Alaska as described above, route the gas to the flare, not to the "compressor suction." Because of this, these compressors would seemingly not meet the definition of "self-contained wet seal compressor." However, there is language in that definition which suggests that the purpose of that definition is that degassed emissions do not route to atmosphere as proposed in §60.5430b and §60.5430c (***emphasis added***). Therefore, API offers the following redline for the definition of self-contained wet seal centrifugal compressor:

> *Self-contained wet seal centrifugal compressor means a wet seal centrifugal compressor system which has an intermediate closed process that degasses most of the gas entrained in the seal oil and sends that gas to either another process or combustion device ~~that is a closed process that ports the degassing emissions to the natural gas line at the compressor suction~~ (**i.e., degassed emissions are recovered**). The de-gas emissions are routed back to ~~suction~~ a process or combustion device directly from the intermediate closed degassing process ~~degassing/sparging chambers~~; after the intermediate closed process ~~-~~the oil is ultimately recycled for recirculation in the seals to the lube oil tank where any small amount of residual gas is released through a vent.*

[89] EPA-HQ-OAR-2021-0317-0808
[90] https://www.epa.gov/sites/production/files/2016-04/documents/smith.pdf
[91] https://www.epa.gov/sites/default/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoildegassing.pdf

Alternatively, as outlined in Comment 10.5.4, EPA could allow all centrifugal compressors the option to comply with the volumetric standard thereby obviating the need for a special definition for a “self-contained wet seal compressor.”

11.0 Leak Detection and Repair at Gas Processing Plants

API supports EPA’s proposal for bimonthly OGI monitoring for equipment leaks at gas processing plants. We also support incorporation of NSPS Vva into NSPS OOOOb and EG OOOOc as an alternative monitoring option with the additional simplifications EPA has proposed. While API also generally supports the use of Appendix K for OGI monitoring at gas processing plants, we have several comments with respect to proposed Appendix K as provided in Attachment A, which are in direct response to EPA’s solicitations within the preamble.

In addition to the above items, API offers the following comments concerning leak detection and repair requirements at gas processing plants.

11.1 Closed vent systems should be monitored annually using OGI or Method 21.

EPA is proposing initial and bi-monthly OGI or quarterly Method 21 monitoring of closed vent systems which are increased monitoring frequencies when compared with the existing annual Method 21 monitoring under NSPS OOOO, NSPS OOOOa, NSPS Vva, and other LDAR regulations. API’s previous comments on this topic[92] were intended to voice support for the use of OGI in monitoring closed vent systems and did not fully consider the implications and minimal environmental benefits of more frequent monitoring.

Closed vent systems have historically been subject only to initial and annual inspections due to their low leak rates. Closed vent systems rarely leak because of the small number of components and lack of constantly moving parts. The hard piping or ductwork in closed vent system do not experience the same wear and tear and potential for leaks as moving parts that generate friction. While OGI does not have the same proximity challenges as Method 21, more frequent monitoring of closed vent systems would still be impractical for both methods as parts of closed vent systems are considered difficult to monitor. More frequent inspections for closed vent systems at gas plants under NSPS OOOOb and EG OOOOc would also be more stringent than the requirements for refineries and chemical plants. Therefore, API recommends that for closed vent systems, hard piping be subject to an initial Method 21 or OGI inspection and annual AVO inspections and ductwork be subject to an initial Method 21 or OGI inspection and annual Method 21 or OGI inspections. If EPA decides to finalize the increased monitoring frequency for closed vent systems, they must provide additional justification including the additional environmental benefits expected from more frequent monitoring of equipment that rarely leak.

Emissions detected from closed vent systems do not constitute a violation of the “no identifiable emissions” standard provided work practice standards are fully implemented. See Comment 5.1 for a more detailed discussion.

[92] EPA-HQ-OAR-2021-0317-0808

11.2 The lack of a VOC or methane concentration threshold expands monitoring requirements with minimal, if any, environmental benefit.

As API noted in its prior comments[93], EPA should retain the current 10 percent by weight threshold for VOC and propose a similar concentration threshold for methane, which we suggested as 1 percent by weight threshold for methane. In the Supplemental Proposal, EPA is proposing that monitoring apply to each piece of equipment "that has the potential to emit methane or VOC", which is effectively a zero-applicability threshold for both methane and VOC.

Some streams at gas processing plants contain methane or VOC but in such low concentrations that monitoring would be meaningless as it would likely always result in no detected emissions. Examples of such streams include but are not limited to purity ethane, acid gas, ancillary chemicals, wastewater, and recycled water. The proposed monitoring of additional components with no appreciable amounts of VOC or methane adds costs and uses personnel resources with minimal, if any, environmental benefit.

In its existing LDAR regulations, EPA has recognized and reaffirmed the need for concentration thresholds to achieve cost-effective emission reductions. The agency has not provided sufficient justification for deviating from this longstanding practice with this rulemaking. Based on an initial review of EPA's TSD[94] from the November 2021 Proposal, API notes the following about EPA's analysis:

- EPA considers only components in VOC service and non-VOC service, which the agency appears to define as follows:

> *"In VOC service" is defined as a component containing or in contact with a process fluid that is at least 10 percent VOC by weight or a component "in wet gas service", which is a component containing or in contact with field gas before extraction. "In non-VOC service" is defined as a component in methane service (at least 10% methane) that is not also in VOC service.*

- EPA estimates VOC and methane emissions and therefore emission reductions and cost-effectiveness using only the following composition ratios identified in Table 10-8 of the TSD:

Component Service	Methane: TOC	VOC: TOC
VOC Service	0.695	0.1930
Non-VOC Service	0.908	0.0251

- EPA appears to treat the "potential to emit to methane" as equivalent to "in non-VOC service" in evaluating control options:

> *In addition to selecting one of the LDAR programs above, the EPA considered which components would be subject to the LDAR program. The current NSPS applies to components in VOC service (Option A). The EPA considered expanding the applicability to include components that have a potential to emit methane, which would add the components classified in this document as non-VOC service components (Option B).*

[93] EPA-HQ-OAR-2021-0317-0808
[94] EPA-HQ-OAR-2021-0317-0166

Therefore, EPA does not appear to fully consider the cost-effectiveness of a potential to emit applicability threshold. API reiterates that EPA should retain the current 10 percent by weight threshold for VOC and establish a similar concentration threshold for methane (suggested as 1 percent by weight). Refer also to Attachment A.

In Comment 11.3, API offers recommended redlines to address this concern. Regarding how to determine when a piece of equipment is not subject to monitoring, the language in §60.5400b(a)(2) should also be revised as appropriate.

11.3 EPA should clarify which equipment is included in the evaluation of capital expenditure.

The definition of equipment is unclear on which equipment is considered when evaluating whether a capital expenditure occurred because capital expenditure is a definition, not a standard or requirement. This lack of clarity could lead to varying interpretations and uncertainty on whether a capital expenditure occurred. For other regulations, EPA has clarified the scope of equipment considered for the affected facility[95]. For leak detection and repair, an appropriate scope would be to apply the same definition of equipment to the capital expenditure evaluation as the standards and requirements. Therefore, the definition of equipment should clearly specify it also applies to capital expenditure.

To address this and the previous comment, API offers the following recommended redlines to definitions in §60.5430b.

> *Equipment, as used in the standards and requirements <u>and for purposes of evaluating capital expenditure in section 60.5365b(f)(1)</u> of this subpart relative to the process unit equipment affected facility at onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector ~~that has the potential to emit~~ <u>in</u> methane or VOC <u>service</u> and any device or system required by those same standards and requirements of this subpart.*
>
> *<u>In methane service means that the piece of equipment contains or contacts a process fluid that is at least 1 percent methane by weight. (The provisions of § 60.5400b(a)(2) specify how to determine that a piece of equipment is not in methane service.)</u>*
>
> *<u>In VOC service means that the piece of equipment contains or contacts a process fluid that is at least 10 percent VOC by weight. (The provisions of § 60.5400b(a)(2) specify how to determine that a piece of equipment is not in VOC service.)</u>*

12.0 Overarching Legal Issues

12.1 The new source trigger date should be December 6, 2022, the date the Supplemental Proposal was published in the Federal Register.

In a memorandum associated with the Supplemental Proposal, EPA "solicits comments on whether CAA § 111(a) provides EPA discretion to define 'new sources' based on the publication date of the Supplemental Proposal and,

[95] U.S. EPA Applicability Determination Index Control Number: 0600027, Modification and Capital Expenditure Calculations, dated February 9, 2001.

if so, whether there are any unique circumstances here that would warrant exercising of such discretion in this rulemaking by the EPA."

API believes that not only does CAA § 111(a) allow EPA to define the new source trigger date based on the publication date of the Supplemental Proposal, but also in fact requires it. Further, as API provides below, there are significant circumstances here that would warrant EPA altering the new source trigger date to December 6, 2022.

As explained in our January 31, 2022 comment letter (EPA-HQ-OAR-2021-0317-0808) on the original NSPS OOOOb and EG OOOOc proposed rule, the original proposal was fundamentally incomplete because no proposed regulatory text was published or otherwise made available at the time of proposal. As a result, that proposal could not serve to set the new source trigger date for new requirements described in the proposed rule.

In the Supplemental Proposal, EPA reasserted that, except for newly proposed standards in the Supplemental Proposal (such as the standards for dry seal centrifugal compressors), the new source trigger date will be the date the original proposal was published in the Federal Register. EPA explains that "CAA Section 307(d)(3) specifies the information that a proposed rule under the CAA must contain, such as a statement of basis, supporting data, and major legal and policy considerations; the list of required information does not include proposed regulatory text." (87 Federal Register (FR) R 74716).

EPA further explains that "the Administrative Procedures Act (APA), which governs most Federal rulemaking, does not require publication of the proposed regulatory text in the Federal Register" and instead specifies that "notice of proposed rulemaking shall include ''*either* the terms or substance of the proposed rule *or* a description of the subjects and issues involved.'' (Emphasis added)." *Id*. EPA concludes that "the APA clearly provides flexibility to describe the ''subjects and issues involved'' as an alternative to inclusion of the ''terms or substance'' of the proposed rule." *Id*.

As an initial matter, EPA's analysis on this point indicates that EPA believes the CAA and the APA provide the flexibility to select November 15, 2021 as the trigger date for new sources, but nothing in EPA's analysis specifically concludes or determines that it must use the November 15, 2021 date. API believes that EPA's rationale for using November 15, 2021 remains flawed for three reasons. The lack of regulatory text (which was neither in the Federal Register notice nor otherwise made available in the docket prior to the close of the comment period) prevents the original proposal from setting the new source trigger date.

First, the CAA § 111(a)(2) definition of "new source" uses the term "proposed *regulations*" in defining the new source trigger date. As we explained in our comments on the original proposal, a preamble unaccompanied by regulatory text is not a "regulation." Here, the preamble to the original proposal was simply a description of the proposed regulations, but by itself did not constitute a proposed regulation because nothing in the preamble was intended by the Agency to constitute an enforceable legal obligation. And it could not, as EPA co-proposed multiple concepts for singular facility types in the November 2021 proposal and requested comment that informed the November 2022 Supplemental Proposal's regulatory text.

For example, in the November 2021 proposal, EPA co-proposed quarterly and semi-annual fugitive emissions surveys for well sites with baseline emissions of 3 or more and less than 8 tons per year of methane. EPA then abandoned the baseline emissions approach in the November 2022 Supplemental Proposal in favor of an equipment threshold. In another example, EPA co-proposed to define affected well facilities in two ways for purposes of the liquids unloading standards. Under one approach, every well that undergoes liquids unloading would be an affected facility; under the other approach, the affected facility would be limited to wells that undergo liquids unloading that is not designed to eliminate venting. These co-proposals, while limited to a subset of the affected facilities, evidence that EPA intended the November 2021 proposal to be conceptual and a means of informing the November 2022 regulatory text.

The November 2022 proposal is complex and requires affected facilities to parse complicated standards that will inform significant capital expenditures and expensive compliance programs. Given the ultimate complexity of the November 2022 regulatory text and scope of impact, the November 2021 proposal's conceptual offerings did not put the regulated community on notice of the "regulations" in any meaningful way that could inform billions of dollars in capital expenditures and compliance program development. Instead, the regulatory text made available in conjunction with the Supplemental Proposal comprises the proposed regulation because that regulatory text defines the enforceable legal obligations that EPA proposes to impose under this rule.

Thus, even if the original proposal may have satisfied the nominal procedural requirements specified by CAA § 307(d) and APA § 553(b) (which it does not for the reasons explained below), the original proposal was not a proposed "regulation" for purposes of setting the new source trigger date under CAA § 111(a)(2). This is particularly true in light of the clear purpose of CAA § 111(a)(2), which is to put affected facilities that are constructed, reconstructed, or modified after the date of a proposed regulation on notice of the requirements that will apply to those facilities upon the effective date of the final regulation. The absence of proposed regulatory text in the original proposal prevents such affected facilities from knowing with reasonable certainty the precise requirements that might actually apply, and thus prevents them from adequately planning for compliance.

Second, EPA's interpretation of CAA § 307(d) and APA § 553(b) is unreasonable and does not make sense in the broader context of these provisions. For example, EPA argues that the required content of a proposed rule specified in CAA § 307(d)(3) does not expressly require regulatory text, but the corresponding content requirements for a final rule (specified in CAA §§ 307(d)(4)(B)(i), (6)(A), and (6)(B)) similarly do not expressly require regulatory text. By EPA's reasoning, that means that the Agency is not required to provide regulatory text as part of a final rule. That is nonsensical. This is particularly true because the record for judicial review is limited to the materials prescribed by CAA §§ 307(d)(3), (d)(4)(B)(i), (6)(A), and (6)(B). CAA § 307(d)(7)(A). If proposed and final rules do not need to include regulatory text, then regulatory text would not be subject to judicial review. That is contrary to reason and the clear intent of the law.

In short, it is simply not plausible to argue that because CAA § 307(d) does not expressly require a proposed rule to include regulatory text; EPA is not required to make proposed regulatory text available at the time of the 2021 "proposal". When considered as a whole, CAA § 307(d) plainly requires rule text to be available.[96]

Third, and more broadly, EPA and the Biden administration made a political judgment to rush issuance of the original proposed rule because the rule constitutes a prominent plank of the administration's climate change regulatory agenda, and it was deemed expedient to issue the proposed rule in conjunction with the 2021 Conference of the Parties to the United Nations Framework Convention on Climate Change in Glasgow, Scotland.[97] The fact that EPA acknowledged the original proposal would require a Supplemental Proposal with

[96] EPA cites *Rybachek v. USEPA*, 904 F.2d 1276, 1297 (9th Cir. 1990) as supporting its position that proposed regulatory text is not necessary. That case is inapposite because the court relies on APA § 553(b)(3). While that provision applies to this rulemaking, the more specific requirements of CAA § 307(d) control here.

[97] EPA's press release for the original proposal is available at U.S. to Sharply Cut Methane Pollution that Threatens the Climate and Public Health | US EPA (""As global leaders convene at this pivotal moment in Glasgow for COP26, it is now abundantly clear that America is back and leading by example in confronting the climate crisis with bold ambition," said EPA Administrator Michael S. Regan**.** "With this historic action, EPA is addressing existing sources

actual regulatory text is plain evidence of the rush. The sheer size of the Supplemental Proposal – 146 pages in the Federal Register, *without* regulatory text (which is provided in the docket) – is further mute evidence of the incomplete nature of the original proposal.

We recognize that every administration has the right to set and implement its regulatory agenda. However, this Administration's desire to expedite issuance of the original proposed rule led to compromises in the usual regulatory procedures, including the decision not to make proposed regulatory text available. It would be unreasonable for affected facilities to bear the burden of those compromises. It is also arbitrary and capricious for EPA to decide to issue an admittedly incomplete proposed rule to satisfy political objectives, and, at the same time, assert that it is somehow complete enough to constitute a "proposed rule" that sets the new source trigger date.

As shown in the analysis above, nothing allows or requires EPA to utilize the November 15, 2021 date. Further, the failure of EPA to provide regulatory text in the November 15, 2021 proposal is reason enough for EPA to "warrant exercising" any discretion it does have with respect to the deadline.

Further, by utilizing November 15, 2021 as the relevant demarcation date, EPA will be including a significant number of sources that were new, modified, or reconstructed between November 15, 2021 and December 6, 2022. For a significant number of the affected facilities, operators will be required to retrofit those new, modified or reconstructed sources to comply with the regulations, including regulations not known to operators at the time of construction, modification or reconstruction. Many of these requirements involve either: (1) substantial capital expenditures for equipment (e.g., instrument air skids and/or generators for use of non-emitting pneumatic controllers); (2) engineering design (e.g., storage tanks, design for any covers and closed vent systems, among others); (3) acquisition (along with all other operators) of a substantial number of part and equipment (e.g., flow meters, calorimeters; and (4) substantial in-field resources for retrofits. Not knowing with reasonable certainty what the final rule would require would significantly complicate implementation of compliance measures, cause the rule to be much more costly for such sources than EPA predicts, and frustrate the regulatory purpose of setting the new source trigger date at the date of proposal (which clearly is intended to provide reasonable notice of the ultimate requirements so that planning can be done at the time of construction, reconstruction, or modification.

In addition, since the onset of the COVID pandemic and continuing to this day, there have been substantial supply chain disruptions, difficulty with obtaining parts and equipment and difficulty with finding personnel (either consulting or for employment) that can assist with implementation of the rule. These supply chain and personnel issues will increase given the extensive nature and reach of NSPS OOOOb alone (given all the operators that will need to comply) – not even accounting for other recent regulatory developments at the state and federal level (e.g., BLM waste prevention rule, Colorado regulatory requirements, and New Mexico requirements – to name a few). EPA will compound this supply chain and personnel concern by maintaining November 15, 2021 as the new source trigger date. EPA's motivation is further obscured given the sources constructed, modified or reconstructed between November 15, 2021 and December 6, 2022 are potentially subject to NSPS OOOOa and may ultimately be subject to EG OOOOc. Thus, API believes that EPA not only has the discretion but the requirement to assign December 6, 2022 as the new source applicability date. Even if this were not required, there is ample basis for EPA to do so for all the reasons previously stated.

from the oil and natural gas industry nationwide, in addition to updating rules for new sources, to ensure robust and lasting cuts in pollution across the country. By building on existing technologies and encouraging innovative new solutions, we are committed to a durable final rule that is anchored in science and the law, that protects communities living near oil and natural gas facilities, and that advances our nation's climate goals under the Paris Agreement."").

12.2 EPA's interest in promoting Environmental Justice is laudable, but EPA must be mindful of the Clean Air Act's boundaries in advancing these goals.

API explained in its comments on the original proposal that we support EPA's attention to potential Environmental Justice (EJ) issues and agree with EPA that the emissions standards prescribed by this rule will significantly reduce emissions from this sector and should result in corresponding risk reductions for all potentially affected individuals. The oil and natural gas industry's top priorities are protecting the public's health and safety – regardless of race, color, national origin, or income – and the environment. We strive to understand, discuss, and appropriately address community concerns with our operations. We are committed to supporting constructive interactions between industry, regulators, and surrounding communities/populations including those that may be disproportionately impacted.

Our comments also explained that, while API supports EPA's EJ goals, the Agency did not provide sufficient detail in the 2021 Proposal to allow API to comment in a meaningful way. EPA has provided additional clarity on two key EJ provisions in the Supplemental Proposal. They are addressed separately below.

12.2.1 Consideration of EJ Impacts in CAA § 111 Standard Setting

First, EPA proposes to require consideration of impacted communities when setting existing source emissions standards that take into consideration remaining useful life and other factors (RULOF). For example, if "a designated facility could be controlled at a certain cost threshold higher than required under the EPA's proposed revisions to the RULOF provision, and such control benefits the communities that would otherwise be adversely impacted by a less stringent standard, the state in accounting for RULOF could choose to use that cost threshold to apply a standard of performance." (87 FR 74824).

EPA believes that it has authority to prescribe such a requirement because "CAA section 111(d) does not specify what are the "other factors" that the EPA's regulations should permit a state to consider", and thus the Agency may "interpret[] this as providing discretion for the EPA to identify the appropriate factors and conditions under which the circumstance may be reasonably invoked in establishing a standard less stringent than the EG." *Id*.

EPA further explains that part of its responsibility in reviewing the adequacy of state CAA § 111(d) existing source emissions control programs is to "determine whether a plan's consideration of RULOF is consistent with section 111(d)'s overall health and welfare objectives." *Id*. "The EPA finds that a lack of consideration to [disparate health and environmental impacts] would be antithetical to the public health and welfare goals of CAA section 111(d) and the CAA generally." *Id*.

Lastly, EPA explains that the "requirement to consider the health and environmental impacts in any standard of performance taking into account RULOF is consistent with the definition of "standard of performance" in CAA section 111(a)(1)" which "requires EPA to take into account health and environmental impacts in determining the BSER." *Id*.

We applaud and support EPA's overall objective of addressing potential disparate impacts. But we are concerned that the Agency's proposal to require such impacts to be addressed when RULOF is considered in setting state standards is not legally supportable.

To begin, the term "other factors" is a generic term in and of itself. But as used in the context of CAA § 111(d), that term does not reasonably mean that EJ may be considered in standard setting. First, CAA § 111(d)(1) states that EPA's regulations "shall permit" states to consider RULOF in setting existing source emissions standards. This language places responsibility on the states, in the first instance, to determine the "other factors" they deem relevant in setting standards upon consideration of RULOF. EPA's role is to review the state determination and not to preemptively specify what factors a state may or may not consider. If a state's identification and consideration of other factors is reasonable, then EPA cannot reject the state's determination on the grounds that EPA believes the term "other factors" should be given a different meaning. EPA's proposed approach is inconsistent with the role Congress intended the states to fulfill as part of the CAA's broader "cooperative federalism" scheme.

Second, the term "other factors" must be interpreted in context. By specifying that states may consider "remaining useful life," Congress indicated that source-specific factors are relevant to the states' determinations. Since the term "other factors" is a catch-all phrase that follows the more specific instruction to consider a source-specific factor, the term "other factors" must be construed in a similar light. This interpretation is particularly true given that "standards of performance" under CAA § 111(a)(1) are technology-based standards that reflect the best system of emissions reduction determined applicable to affected facilities. EPA's proposed interpretation of "other factors" is inconsistent with this source-specific, technology-based regulatory scheme.

Third, unlike other standards under the CAA, CAA § 111 does not require or allow for standards to be based on an assessment of impacts regarding health or the environment. Where the CAA confers such authority, it does so expressly and usually in a context where criteria exist to determine the adequacy of such standards. For example, CAA § 112(f) requires impacts to health and the environment to be considered in determining whether "MACT"[98]-based NESHAPs are adequately protective to health and the environment. The statute specifies that EPA must provide an "ample margin of safety," as defined in the Benzene Waste NESHAP. CAA § 112(f)(2)(A), (B). The Title I air quality program is also designed in this fashion – with the National Ambient Air Quality Standards (NAAQS) established as the benchmark for acceptable air quality and the guidepost for formulating appropriate state programs.

Here, CAA § 111 does not provide any indication that EPA must or may consider health or environmental impacts associated with air emissions from affected facilities in determining BSER and in setting emissions standards. For over 50 years, CAA § 111 has properly been construed as a technology-based program designed to prescribe standards based primarily on consideration of the best available technologies that are adequately demonstrated and not cost prohibitive. EPA's goals here are important but would require standards to be based on impacts analyses of air emissions from affected facilities – an approach that is not incorporated into the CAA § 111 standard setting process.

EPA also states that not considering impacts would be "antithetical to the public health and welfare goals of CAA Section 111(d) and the CAA generally." There is no doubt that protecting public health and welfare are overarching goals of the CAA. That aspiration does not in itself confer regulatory authority that is not otherwise prescribed by the statute. Congress carefully designed the regulatory tools it intends EPA to use to accomplish an adequate degree of protection to health and welfare. For the reasons explained above, CAA § 111(d) does not require or allow for consideration of health or environmental impacts in standard setting.

Lastly, EPA argues that considering EJ impacts in state standard setting "is consistent with the definition of "standard of performance" in CAA Section 111(a)(1)" and that states must consider such impacts "just as the EPA is statutorily required to take into account these factors in making its BSER determination." *Id*. at 74824. More specifically, EPA asserts that the definition of "standard of performance" "requires the EPA to take into account health and environmental impacts in determining the BSER." *Id*. We respectfully disagree, as there is no language

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in the CAA § 111(a)(1) definition of "standard of performance" that requires or allows health or environmental impacts associated with air emissions from affected facilities to be factored into standard setting.

As explained above, that definition requires standards of performance to primarily be based on technology and cost considerations. The only exception is that "nonair quality health and environmental impact[s] and energy requirements" also must be taken into account in setting standards of performance. CAA § 111(a)(1). The statute thus is clear that the only "health and environmental impacts" that may be considered in setting a standard of performance are ***nonair*** health and environmental impacts. That provision traditionally has been interpreted to require EPA to consider cross-media impacts (e.g., wastewater created by an air emissions scrubber) so as not to create a different environmental issue through technical requirements meant to address air quality. Because the analysis that EPA would require here would focus on air emissions impacts, it cannot be grounded in the requirement to consider ***nonair*** quality health and environmental impacts. Moreover, because the statute specifies that only nonair quality health and environmental impacts may be considered in standard setting, EPA is precluded from interpreting general language in CAA § 111(a)(1) or 111(d)(1) as somehow authorizing consideration of air quality-based health or environmental impacts.

For all of these reasons, EPA should reconsider the proposed requirement to require consideration of EJ impacts when states or EPA implement the RULOF provision.

12.2.2 Requirement that states provide for "meaningful engagement" in their CAA § 111(d) programs.

The Supplemental Proposal provides further details and additional explanation of the proposal to require states to provide for "meaningful engagement" as part of their CAA § 111(d) regulatory programs. According to EPA, "[t]he fundamental purpose of CAA section 111 is to reduce emissions from certain stationary sources that cause, or significantly contribute to, air pollution which may reasonably be anticipated to endanger public health or welfare" (87 FR 74827). As a result, EPA asserts that "a key consideration in the state's development of a state plan, in any significant plan revision, and in the EPA's development of a Federal plan pursuant to an EG promulgated under CAA section 111(d) is the potential impact of the proposed plan requirements on public health and welfare." *Id*. "A robust and meaningful public participation process during plan development is critical to ensuring that the full range of these impacts are understood and considered." *Id*.

The "meaningful engagement" requirement is grounded in the assertion that "a fundamental purpose of the Act's notice and public hearing requirements is for all affected members of the public, and not just a particular subset, to participate in pollution control planning processes that impact their health and welfare." *Id*. at 74828-9. In explaining the legal basis for this requirement, EPA states that "[g]iven the public health and welfare objectives of CAA section 111(d) in regulating specific existing sources, the EPA believes it is reasonable to require meaningful engagement as part of the state plan development public participation process in order to further these objectives." "Additionally, CAA section 301(a)(1) provides that the EPA is authorized to prescribe such regulations ''as are necessary to carry out [its] functions under [the CAA].'' The proposed meaningful engagement requirements would effectuate the EPA's function under CAA section 111(d) in prescribing a process under which states submit plans to implement the statutory directives of this section." *Id*. at 74829.

API supports full and fair public process in the development and implementation of CAA programs, including state CAA § 111(d) programs. All affected entities should have a reasonable opportunity to know about and participate in the development of regulations that affect their interests. In that light, we offer the following comments on the proposed "meaningful engagement" requirement.

First, CAA § 111(d) states only that EPA shall establish a "procedure similar to that provided by section 7410 of this title under which each State shall submit to the Administrator a plan." This requirement to establish a "procedure" for "submit[ting] … a plan" unambiguously is directed only at the review and approval process as between the states and EPA and is not directed at the plan development process that must be followed by the state. In other words, CAA § 111(d) directs EPA to emulate only some of the CAA § 110 requirements – not all of them.

Thus, CAA § 111(d) does not allow EPA to impose upon the states any measures related to the process by which they develop their plans. It only provides authority to set up a process by which EPA reviews and approves the adequacy of standards of performance and the measures adopted by the states to implement and enforce such standards.

Second, to the extent that a "reasonable notice" standard applies to the development of state plans under CAA § 111(d), it is the states' responsibility to ascertain what is reasonable – not EPA's. CAA § 111(d) is one of many CAA provisions where Congress intentionally split responsibility between EPA and the states. Indeed, under this "cooperative federalism" scheme, "air pollution control at its source is the primary responsibility of States and local governments." CAA § 101(a)(3). In the earliest days of the CAA, the U.S. Supreme Court confirmed that the CAA "gives the Agency no authority to question the wisdom of a State's choices of emission limitations" if the limitations accomplish the goals of the CAA. *Train v. NRDC*, 421 U.S. 60, 79 (1975).

Implicit in the notion of cooperative federalism is that states not only have wide latitude to determine appropriate emissions limitations, but also have similarly wide latitude in the legal and regulatory processes by which such limitations are established. Thus, to the degree a "reasonable notice" obligation is imposed upon the states by CAA § 111(d), the states have primary authority and responsibility to determine how to implement this requirement. While EPA has responsibility to review and approve state programs, it may not require states to follow what it believes to be the most reasonable notice procedures. Instead, EPA must approve any state notice requirements that are facially reasonable, even if those are not the procedures EPA itself would have selected.

Third, even if EPA has authority to define what constitutes "reasonable notice" during the development of state plans, the proposed "meaningful engagement" requirement goes beyond what EPA may reasonably require. To begin, the term "notice" unambiguously means notification of those with interest in the matter at hand. The proposed requirements to engage with particular groups in particular ways (e.g., states must seek to overcome "barriers to participation" by "pertinent stakeholders") and make targeted outreach go well beyond the nominal statutory obligation of notification. EPA may "think [its] approach makes for better policy, but policy considerations cannot create an ambiguity when the words on the page are clear." *SAS Institute Inc. v. Iancu*, 138 S. Ct. 1348, 1358 (2018). Congress has imposed no explicit requirements and stated no intent in CAA § 111 or anywhere else in the CAA related accomplishing any particular environmental justice goals or outcomes. The word "notice" cannot carry as much meaning as EPA believes it should.

As for CAA § 301, it has long been understood that that provision does not "provide [EPA] Carte blanche authority to promulgate any rules, on any matter relating to the Clean Air Act, in any manner that the [EPA] wishes." *North Carolina v. EPA*, 531 F. 3d 896, 922 (D.C. Cir. 2008) (internal quotes and citations omitted). Here, CAA § 301(a)(1) is inapplicable because creating a new category of procedural requirements is not "necessary" for the Administrator "to carry out his functions under this chapter." CAA § 301(a)(1). As noted above, EPA's intentions are commendable. But the proposed "meaningful engagement" procedures are not "necessary" as that term is used in CAA § 301.

Lastly, EPA's proposed "meaningful engagement" procedures are are not adequately clear and objective. As noted above, Congress has not spoken in the CAA to the issue of environmental justice. EPA and interested parties are without guidance as to whether the issue should be addressed under the CAA and, if so, how.[99] Moreover, EPA's criteria for determining the adequacy of state "meaningful engagement" efforts are vague and EPA's authority under its proposed rules to accept or deny a state's efforts is not bounded by any readily objectively discernable principles. For example, how does EPA determine the manner of required engagement with any particular stakeholders? How does EPA decide what constitutes an actionable "linguistic, cultural, institutional, geographic, [or] other barrier" and, where such barriers are determined to exist, whether the state's proposed approach is sufficient? What measures are needed for state programs to be adequately inclusive? These are all weighty questions that the statute does not expressly address and that EPA leaves fundamentally uncertain in its proposed rule. As a result, the proposed rule is vague, unmoored to the statute, and unless corrected, would be arbitrary and capricious. *Motor Vehicle Mfrs. Assn. v. State Farm*, 463 U.S. 29, 43 (1983).

For these reasons, "meaningful engagement" should be encouraged by EPA but cannot be a required element of approvable state CAA § 111(d) programs.

12.3 EPA does not explain the legal basis for its proposal to empower third parties to conduct remote monitoring that may trigger enforceable obligations by affected facilities.

In the original proposal, EPA presented a preliminary concept that would "take advantage of the opportunities presented by the increasing use of [advanced methane detection systems] to help identify and remediate large emission events (commonly known as "super-emitters")" (86 FR 63177). EPA sought comment on "how to evaluate, design, and implement a program whereby communities and others could identify large emission events and, where there is credible information of such a large emission event, provide that information to owners and operators for subsequent investigation and remediation of the event." *Id*.

As we explained at the time, API concurs with the importance of identifying and addressing large emissions events. Emissions from such events have the potential to be much greater than those from normal operations at a given facility. API shares EPA's interest in seeking to reduce the incidence of such large emissions events.

We noted in our comments that the proposed "Super Emitter Response Program" was unique in that it would be the first time under the CAA that EPA asserts authority to create regulatory obligations for affected facilities based on monitoring conducted by unaffiliated third parties. We further noted EPA did not explain the legal basis for establishing such a requirement and explained that an explanation from EPA was essential to understanding whether such a novel provision is legally viable.

Unfortunately, the Supplemental Proposal does not provide the needed explanation. That failure to explain the legal underpinnings of such a key element of the proposal violates the CAA § 307(d)(3)(C) requirement to include as part of the proposed rule "the major legal interpretations underlying the proposed rule." If not cured, it also would render the final rule arbitrary and capricious because EPA would have failed to address and explain a key factor underlying this aspect of the final rule.

[99] It is notable that the 2022 "Inflation Reduction Act" included the most significant amendments to the CAA in decades and specifically targeted Environmental Justice concerns, yet Congress stopped short of amending CAA § 111 or the other existing substantive CAA programs to require or allow consideration of EJ. In other words, Congress expansively addressed EJ, but did so by providing copious funding to address the issue and chose not to create obligation or authority to otherwise address or consider EJ in implementing the existing CAA substantive programs.

To be sure, the Supplemental Proposal includes a lengthy discussion in the preamble called the "Statutory Basis of Super-Emitter Program" (87 FR 74752). For some four pages, EPA delves deeply into two explanations as to how it believes "the proposed super-emitter response program … fits within the EPA's authority under section 111 of the CAA." *Id*. In particular, EPA explains how the program might be justified by treating super-emitting events as an affected facility warranting a § 111 emissions standard and, alternatively, how the "super-emitter response program can be justified as part of the standards and requirements that apply to individual affected/designated facilities under this rule" (either as an added compliance assurance measure or as additional equipment leak work practices). *Id*. at 74752-4.

As for those suggestions, API disagrees with EPA's contention that it has authority to treat super-emitting events as an affected facility warranting a § 111 standard of performance. Rather, at most, EPA has the authority to consider identification of super-emitter events as "monitoring" for an affected facility. As such, super-emitters may only be regulated at facilities that already are subject to NSPS OOOOb or EG OOOOc for other reasons. In other words, if a thief hatch on an NSPS OOOOb storage vessel were left open, it could (if meeting the threshold – and subject to the legal concerns set forth below) be considered a super-emitter, and EPA could require corrective action to close the thief hatch. This would be similar for emissions above the threshold from an unlit flare or control device that is mandated by NSPS OOOOb or EG OOOOc (once applicable). However, a super-emitter cannot arise from equipment at a stationary source that is not already an affected facility.

In other words, if an aerial survey identified emissions from a thief hatch on a storage vessel that is not subject to NSPS OOOOb, and the storage vessel is not yet subject to EG OOOOc, then this cannot be a super-emitter affected facility subject to the regulations and for which an operator has to take corrective action. EPA's preamble appears to support this approach in several places, but does not specifically state this in the rule. Thus, as written, it appears that one could identify a super-emitter at a stationary source that has no affected facilities or from equipment that is not an affected facility. EPA has not justified that super-emitters – many of which are malfunctions – are or can be independently considered "affected facilities" under CAA § 111.

An in any event, nowhere in this lengthy discussion – nor in any other part of the preamble or supporting documents – does EPA explain where in the CAA it finds authority to empower third parties to submit monitoring information to an affected/designated facility that triggers regulatory obligations for the facility under the rule. The need for a legal explanation is particularly necessary here, given that this is the first time that EPA has sought to establish such a requirement under CAA § 111 or, to our knowledge, under the CAA as a whole.

We also note that EPA provides a lengthy discussion of the policy rationale that stands behind the proposed Super-Emitter Response Program, including an extensive explanation of how EPA believes that "[t]he design of the super-emitter response program ensures that the EPA will make all of the critical policy decisions and fully oversee the program." *Id*. at 74749-51. In EPA's view, "the qualified third party would essentially only be permitted to engage in certain fact-finding activities and issue fact-based notifications within the limited confines that EPA has authorized." *Id*. at 74750. Moreover, such notifications "originating from third parties would not represent the initiation of an enforcement action by the EPA or a delegated authority." These arguments indirectly speak to EPA's assertion of possible legal authority, but the policy rationale by itself cannot legally justify EPA's novel proposal to empower citizens to develop and submit information that triggers legal obligations for affected/designated facilities.

We lastly note that, in our comments on the original proposal, we explained that CAA § 304 expressly prescribes a role for citizens in CAA implementation by authorizing them to file civil lawsuits challenging alleged violations of, among other things, CAA § 111 emissions standards. We pointed out that Congress did not provide similar express language in CAA § 111 or elsewhere in the CAA authorizing citizen monitoring as provided in the proposed super-emitter response program. In this context, the absence of such language should be construed as a limitation on EPA's authority to allow such monitoring and such an absence is not an implicit delegation of authority from Congress to EPA.

As a further note on the relevance of CAA § 304, that section prescribes strict criteria for obtaining injunctive relief to address alleged CAA violations – including prior notice, opportunity for the government to take the lead on an enforcement action, standing to bring an enforcement case, proof of liability, and sufficient rationale to support injunctive relief. The proposal runs counter to CAA § 304 by enabling citizens to obtain injunctive relief through the super-emitter response program (in this case, investigation, corrective action, root cause analysis, and related measures) without satisfying the procedural and substantive criteria that must be met to obtain such relief under CAA § 304.

12.4 The 100 kg/hr emissions threshold for defining a "super-emitter" is not adequately justified.

As a wholly different concern, EPA proposes to "define a super-emitter emissions event as any emissions detected using remote detection methods with a quantified emission rate of 100 kg/hr of methane or greater." *Id*. at 74749. While EPA provides a lengthy explanation of how that threshold was determined and why EPA believes it is appropriate, the overarching rationale is that the Agency believes that this threshold captures "very large emissions events." *Id*. Indeed, the term "super-emitter" clearly was coined to describe the intended scope of coverage.

Yet just a few months ago, when addressing essentially the same issue under Subpart W of the Greenhouse Gas Reporting Program, EPA proposed to establish a new reporting requirement for "other large release events," which EPA proposed to define as "events that release at least 250 mtCO_2e per event." 87 Fed. Reg. 36920, 36982 (June 21, 2022). In explaining its rationale for setting this threshold, EPA explains that, "[w]hile some sources covered by subpart W methodologies, such as equipment leaks, may represent ''malfunctioning'' equipment, these sources are ubiquitous across the oil and gas sector [and] are generally small." *Id*. The proposed 250 mt reporting threshold is intended to capture "large emissions events." *Id*. EPA derived the value by assessing "other emissions sources that [it] considered large." *Id*. The threshold was expressly designed to be considerably lower than the emissions rates estimated for the largest release events (e.g., Aliso Canyon or Ohio well blowouts), and compares favorably to a similar reporting requirement under Subpart Y for petroleum refinery flares. *Id*. at 36983.

Despite the obvious similarities between the proposed Subpart W large emissions event proposal and the proposed NSPS OOOOb and EG OOOOc super-emitter proposal, EPA fails to mention the Subpart W proposal when explaining in the NSPS OOOOb and EG OOOOc proposal its rationale for establishing the emissions threshold for super-emitting events. The omission is particularly striking given the significant differences between the two proposals as to what EPA believes to be a large-emitting event. For example, EPA proposes to apply a kg/hr metric in NSPS OOOOb and EG OOOOc versus an event-based metric for Subpart W. Additionally, the proposed NSPS OOOOb and EG OOOOc threshold of 100 kg/hr is facially much lower than the 250 mt per event threshold in Subpart W. The Subpart OOOOb and OOOOc proposal would define events as "super-emitting" that EPA in the Subpart W proposal dismisses as "ubiquitous" and "generally small."

Clearly, the two proposed rules are contradictory in many relevant aspects. EPA has not provided any explanation in the NSPS OOOOb and EG OOOOc original or Supplemental Proposals as to why the proposed definition of "super-emitter" makes sense in light of the proposed rules for large event release reporting under Subpart W.

Lack of such an explanation would render this aspect of the final NSPS OOOOb and EG OOOOc rule arbitrary and capricious. Moreover, even if EPA provides an explanation in the final rule, the definition of "super-emitter" is of central relevance to the Super-Emitter Response Program and, thus, failure to provide an opportunity for public notice and comment on its explanation would violate the CAA § 307(d) procedural rulemaking requirements.

12.5 EPA's proposed approach to reconciling the applicability of NSPS OOOO, OOOOa, OOOOb, and EG OOOOc is contrary to law and unreasonable.

In our comments on the original proposal, we noted that the proposal did not include any discussion or analysis of the complex issues surrounding the applicability of the various NSPS OOOO subparts. We pointed in particular to the complexities related to the fact that the various subparts do not completely overlap – Subpart OOOO applies only to volatile organic compounds (VOCs), Subparts OOOOa and OOOOb apply to VOCs and greenhouse gases (GHGs), and EG OOOOc applies only to GHGs. Also, the affected/designated facilities are not the same under these rules. We also highlighted the question of whether a source that is an affected facility that is regulated as a new source under an existing NSPS can also be an "existing" facility under a subsequent CAA § 111(d) rule. Another important omission was any citation or explanation/analysis by EPA of the applicable law.

The Supplemental Proposal does not resolve these issues. To be sure, EPA provides an explanation of how it believes "the proposed EG OOOOc [will] impact sources already subject to NSPS KKK, NSPS OOOO, or NSPS OOOOa." (87 FR 74716). But that explanation is fundamentally incomplete because EPA still does not provide any legal analysis explaining how or why its proposed analysis is required or allowed under the law. The full extent of EPA's legal discussion on this topic is the conclusory assertion that:

> *Under CAA section 111, a source is either new, i.e., construction, reconstruction, or modification commenced after a proposed NSPS is published in the Federal Register (CAA section 111(a)(1)), or existing, i.e., any source other than a new source (CAA section 111(a)(6)). Accordingly, any source that is not subject to the proposed NSPS OOOOb as described is an existing source subject to EG OOOOc.*

Id. at 74716.

That simple explanation does not provide sufficient detail on the key legal questions we presented in our prior comments. For example, EPA does not explain how the law requires or can be interpreted to require a source to be regulated as a "new" source under a prior NSPS and, at the same time, be regulated as an "existing" source under a subsequent CAA § 111(d) program. It is clear that EPA presumes that this is how the law works. For example, the Agency repeatedly asserts that Subpart OOOOc standards "would satisfy compliance with" previously applicable NSPS – clearly implying that both standards would apply. See *Id.* at 74716-8. But the Supplemental Proposal does not explain why this outcome (applicability of both new and existing source standards to the same affected/designated facility) must or may be prescribed under the law.

EPA's silence on this important matter is particularly pronounced because EPA has never taken the position a that previously applicable NSPS continues to apply to an affected facility that triggers the applicability of a subsequent standard. For example, VOC emissions from storage vessels are regulated under both Subpart OOOO and Subpart OOOOa. It is easily conceivable that a given storage vessel might have triggered Subpart OOOO because it was constructed one month after that standard was proposed and then subsequently triggered Subpart OOOOa because the storage vessel was modified two months after that standard was proposed. It is well understood that, in such a circumstance, the Subpart OOOO storage vessel requirements cease to apply after the corresponding

Subpart OOOOa requirements are triggered. The approach to reconciling applicability suggested in the Supplemental Proposal cannot be reconciled with EPA's historic practice.

More broadly, EPA fails in both the original and Supplemental Proposals to explain how the law must or can be construed to determine what standard applies to a given source when: (1) the source is regulated as a new source under a prior version of an NSPS (such as Subpart OOOO) and then triggers a subsequent version of that new source standard (such as Subpart OOOOa); (2) the source is regulated as a new source under an existing new source standard (such as Subpart OOOO or OOOOa) and is in existence when a subsequent Section 111(d) existing source standard is proposed (such as EG OOOOc) and subsequently take effect; and (3) a source is regulated as an existing source under a Section 111(d) standard (such as EG OOOOc) and is subsequently modified or reconstructed such that it triggers a corresponding new source standard (such as NSPS OOOOb).

In sum, EPA fails to acknowledge the complexities and ambiguities as to how the law applies to this situation and fails to provide relevant legal analysis on these points. Unless EPA corrects these problems, the final rule will be both procedurally flawed (for failure to satisfy the CAA § 307(d)(3) obligation for EPA to address in the proposed rule that major legal interpretations underlying the proposed rule and to provide an opportunity for public comment) and arbitrary and capricious (for failure to address key factors underlying applicability of the various subparts). We note the legal basis for the applicability scheme for these rules is an issue of central relevance because the scope of applicability is fundamental to proper implementation and coordination of these rules.

12.6 EPA must provide more flexibility for approving state programs.

The Supplemental Proposal includes a lengthy discussion of the approach and criteria by which EPA proposes to review and approve/disapprove state CAA § 111(d) existing source programs. We have comments and recommendations on several elements of EPA's proposed approach.

All of our comments flow from the fundamental guiding principle that EPA is required to approve state programs that satisfy CAA § 111(d) standard setting criteria and cannot approve state programs that do not meet those criteria.[100] EPA correctly sums up this principle when it states "that its authority is constrained to approving measures which comport with applicable statutory requirements" (87 FR 74826 n. 274). The problems with EPA's proposal regarding approval of state programs all are grounded in violations of this principle.

To begin, EPA exceeds its authority by seeking in many places to impose its own preferences on state programs rather than recognizing that it must approve any state program that meets the statutory criteria – even programs that include elements that EPA itself would not choose, but that objectively do meet statutory standard setting requirements. In other words, if a state program meets express statutory requirements or otherwise is grounded on a reasonable construction of statutory requirements, EPA has no choice but to approve the program.

For example, EPA repeatedly and wrongly asserts that its "presumptive standards" must be used to judge the adequacy of state programs. See, e.g., *Id*. at 74812 ("a state program must establish standards of performance that are in the same form as the presumptive standards"); *Id*. ("EPA is also proposing to interpret CAA section 111 to authorize states to establish standards of performance for their sources that, in the aggregate, would be equivalent to the presumptive standards"). Using EPA's presumptive standards as a measure of acceptability is wrong because a state's obligation under CAA § 111(d) is to establish standards of performance based on BSER.

[100] The only other state obligation is to satisfy the nominal procedural requirements that EPA establishes for submission, review, and approval of state CAA § 111(d) programs.

CAA §§ 111(a)(1) and (d)(1). EPA's "presumptive standards" do not constitute BSER. Rather, they represent EPA's notion of what emissions standard might reasonably satisfy EPA's BSER determinations. But the statute unambiguously provides that states have authority and responsibility to fashion a standard that meets BSER and is not limited to the "presumptive standard" that EPA thinks is best.

Notably, EPA clearly understands that is what the statute requires. EPA itself states that "Section 111(d) does not, by its terms, preclude states from having flexibility in determining which measures will best achieve compliance with the EPA's emission guidelines. Such flexibility is consistent with the framework of cooperative federalism that CAA section 111(d) establishes, which vests states with substantial discretion" (87 FR 74812). EPA's acknowledgment that it is the states' obligation to determine what measures "best" satisfy EPA's BSER determination is a correct statement of the law and contradicts the idea that EPA gets to decide what is "best" and impose that judgment on the states.

On a related note, EPA here indicates its commitment to faithfully implementing the "framework of cooperative federalism that CAA section 111(d) establishes," which necessarily requires EPA to defer to (and approve) state measures that satisfy the law, even when such measures do not satisfy EPA's own preferences. See also *Id*. at 74826 (EPA proposing to defer to the state's discretion to impose more costly controls). Yet on the other hand, a primary rationale for the proposed prescriptive measures for reviewing and approving/denying state programs is concern about inconsistency from state to state (e.g., *id*. at 74818 ("two states could consider RULOF for two identically situated designated facilities and apply completely different standards of performance on the basis of the same factors")) and the possibility that certain state programs will be less stringent than EPA believes they should be (e.g., *id*. at 74817 (lack of a clear framework might allow states to "set less stringent standards that could effectively undermine the overall presumptive level of stringency envisioned by the EPA's BSER determination and render it meaningless")). EPA cannot have it both ways – i.e., support state flexibility when it promotes EPA's preferred outcomes and discourage state flexibility when needed to achieve such outcomes. Such an inconsistent approach is facially arbitrary. It is easily resolved by allowing the state flexibility that EPA acknowledges to exist and, in any event, that is demanded by the statute.

Another flaw in EPA's approach is its proposal to give substantive meaning to the statutory obligation that it must approve state plans that are "satisfactory." CAA § 111(d)(2)(A). For example, EPA explains that "it is the EPA's responsibility to determine whether a state plan is "satisfactory" (87 FR 74818). EPA further explains that "the most reasonable interpretation of a ''satisfactory plan'' is a CAA section 111(d) plan that meets the applicable conditions or requirements, including those under the implementing regulations that the EPA is directed to promulgate pursuant to CAA section 111(d)." *Id*. See also *id*. at 74824 ("CAA section 111(d)(2)'s requirement that the EPA determine whether a state plan is ''satisfactory'' applies to such plan's consideration of RULOF in applying a standard of performance to a particular facility. Accordingly, the EPA must determine whether a plan's consideration of RULOF is consistent with section 111(d)'s overall health and welfare objectives.").

So, by EPA's reasoning, all elements of its CAA § 111(d) implementing regulations become mandatory state obligations because, if a state does not in EPA's eyes satisfy the regulations, the state program is not "satisfactory" to EPA. Similarly, EPA gets to decide whether a state plan is "satisfactory" based on EPA's judgment as to whether the plan meets EPA's conception of the "overall health and welfare objectives" of CAA § 111(d). In other words, EPA uses the term "satisfactory" to bootstrap its own policy and legal preferences into mandatory approvability criteria.

EPA's interpretation is inconsistent with the plain words of the statute and, in any event, unreasonably expands EPA's authority to prescribe or prohibit particular outcomes under state CAA § 111(d) programs. The statute simply says that state plans must be "satisfactory." The word "satisfactory" naturally connotes that EPA must approve any state plan that meets the statutory standard setting criteria and that otherwise meet the nominal procedural rules that EPA is required to establish to guide submission and review/approval of state plans. The word "satisfactory" does not reasonably confer upon EPA the authority to demand particular outcomes (e.g., meeting EPA's self-determined "health and welfare objectives") or to impose substantive constraints not otherwise specified by CAA § 111(d). EPA's effort to give more meaning to the word "satisfactory" is inconsistent with the law and a misplaced effort to expand the Agency's authority under CAA § 111(d).

Lastly, EPA explains that when a state decides to establish a standard of performance based on consideration of remaining useful life and other factors, it must "determine and include, as part of the plan submission, a source-specific BSER for the designated facility" (87 FR 74821). EPA then prescribes criteria that the state must follow in determining BSER and setting a corresponding emissions standard. *Id*. This is the first time in this rulemaking (and, to our knowledge, the first time ever) that EPA has interpreted the statute as authorizing and requiring a state to conduct a BSER analysis under CAA § 111(d) rather than setting standards of performance based on an EPA BSER determination.

We agree with EPA that, when a state considers RULOF in setting emissions standards for a particular source or group of sources, it necessarily must conduct a BSER analysis as part of its analysis. When a state considers RULOF, EPA's own BSER analysis ceases to have meaning because fundamental elements of that analysis – such as the cost assessment and determination that a particular emissions control method is feasible or has been adequately demonstrated – cease to apply to the source(s) covered by the state RULOF analysis.

EPA asserts that "the statute requires the EPA to determine the BSER by considering control methods that it considers to be adequately demonstrated, and then determining which are the best systems by evaluating: (1) The cost of achieving such reduction, (2) any non-air quality health and environmental impacts, (3) energy requirements, (4) the amount of reductions, and (5) advancement of technology" and that "a state must also consider all these factors in applying RULOF for that source." *Id*. We agree that the statute requires the first three criteria to be considered in determining BSER. We agree that application of these criteria is consistent with the principle that state CAA § 111(d) plans must meet the statutory standard setting criteria. We do not agree that the statute specifies or requires that BSER also must be based on an assessment of "the amount of reductions" or "advancement of technology." A state has the discretion to consider these factors, but EPA cannot impose these factors on a state because the statute itself does not require that they be considered.

EPA goes on to assert that a state BSER analysis "must identify all control technologies available for the source and evaluate the BSER factors for each technology, using the same metrics and evaluating them in the same manner as the EPA did in developing the EG using the five criteria noted above." *Id*. We disagree. The state clearly must determine BSER based on the express statutory criteria. But the law does not require a state BSER analysis to "identify all control technologies available for the source," "use the same metrics," or provide an evaluation "in the same manner" as EPA used in developing its BSER analysis. These may represent EPA's preferred method of determining BSER, but nothing in the law requires a state to follow EPA's preferred method or authorizes EPA to reject a state standard that is based on a BSER determination that employs a different approach than EPA's.

12.7 EPA does not have authority to approve more stringent state programs that are based on consideration of remaining useful life and other factors.

In the original proposal, EPA offered an extensive explanation of why it now believes it has authority to approve state § 111(d) programs that are more stringent than would be required by application of the BSER determined by

EPA. That position is expanded in the Supplemental Proposal by EPA's assertion that "states may consider RULOF to include more stringent standards of performance in their state plans" (87 FR 74825). This position represents a complete reversal of the current Subpart B provision limiting application of "RULOF" to establishing less stringent measures (See 86 FR 63251).

EPA now asserts that the term "other factors" is ambiguous and that EPA "may reasonably interpret[] this phrase as authorizing states to consider other factors in exercising their discretion to apply a more stringent standard to a particular source" (87 FR 74825). Moreover, EPA now rejects the idea that the § 111(d) Subpart B variance provisions are relevant in interpreting the scope of the Agency's authority to approve more stringent standards based on consideration of RULOF. *Id*. EPA also rejects its prior analysis of the legislative history on the grounds that it provides no meaningful guidance to EPA. *Id*. at 74826. Lastly, EPA argues that its new interpretation is consistent with the purposes of CAA § 111(d) – i.e., "to require emission reductions from existing sources for certain pollutants that endanger public health or welfare." *Id*.

EPA's attempt to reverse its position here is misplaced and is not supported by the law. First, as we discuss above, the term "other factors" is not a carte blanche invitation from Congress for EPA to create whatever plausibly "reasonable" new authorities or constraints it might conceive. The term "other factors" must be interpreted in context. As EPA itself explains, the term "remaining useful life … is a factor that inherently suggests a less stringent standard." *Id*. In this context, it stands to reason that Congress intended the term "other factors" to be interpreted such that "other factors" are applied in the same way (to reduce rather than increase stringency). Because the term "other factors" is a catch-all phrase that follows the more specific instruction to consider a source-specific factor, the term "other factors" must be construed in this manner.

Second, EPA's position is grounded in its assertion that states are not required "to conduct a source-specific BSER analysis for purposes of applying a more stringent standard" because "[s]o long as the standard will achieve equivalent or better emission reductions than required by EG OOOOc, the EPA believes it is appropriate to defer to the state's discretion to, e.g., choose to impose more costly controls on an individual source." *Id*. at n. 273. At the same time, EPA correctly notes that "its authority is constrained to approving measures which comport with applicable statutory requirements." *Id*. at n. 274; see also *Id*. at 74813 (EPA may not approve and thereby "federalize" state programs that apply to pollutants and/or affected facilities not covered by Subpart OOOOc).

It is inconsistent and arbitrary for EPA to assert that a state must conduct a new source-specific BSER analysis if it wants to use RULOF to establish a less stringent standard than would be required under EPA's BSER determination (see *Id.* at 74821), while a state is not similarly constrained when establishing more stringent standards. EPA's assertion that a more stringent standard does not require a BSER analysis because it "will achieve equivalent or better emissions reductions than required by EG OOOOc" cannot be squared with the requirement that alternative state measures must "comport with applicable statutory requirements" – which in this case include the unambiguous requirement that BSER and corresponding emissions standards must be demonstrated in practice and cost effective. EPA's suggestion that it may defer to (and approve) more stringent state requirements simply because they are more stringent is wrong because that approach does not ensure that the more stringent standards meet the statutory standard-setting criteria.

12.8 The proposed well closure requirements are not needed as a practical matter and mostly beyond EPA's authority as a legal matter.

In the original proposal, EPA raised in concept the possibility of setting standards "to address issues with emissions from abandoned, or non-producing oil and natural gas wells that are not plugged or are plugged ineffectively" (86 FR 63240). We explained in our comments that emissions from abandoned wells are not as great as EPA suggests and that issues related to well closure are more appropriately addressed by the states and BLM. We also explained that, if EPA decided to move ahead with such standards, the possibility of requiring a demonstration of financial capacity should not be a part of that proposed rule given EPA has no authority under the Clean Air Act to impose a financial assurance requirement.

In the Supplemental Proposal, EPA proposes regulations governing well closures in both NSPS OOOOb and EG OOOOc (87 FR 74736). The proposed rules closely track the concept outlined in the original proposal – including a requirement for developing and submitting a well closure plan within 30 days of the cessation of production from all wells at a well site, which must describe the steps that will be taken to close the well, proof of financial assurance, and a schedule for completing the closure. *Id*. Monitoring must be conducted after closure to demonstrate that there are no emissions from the closed well. *Id*. And changes in ownership must be reported on an annual basis during the life of a well. *Id*.

In light of this proposal, we reiterate our prior argument that the CAA does not grant EPA authority to impose financial assurance requirements.[101] We add that EPA did not respond to these comments in the Supplemental Proposal. We further note that EPA did not explain the legal basis for the proposed financial assurance requirements in either the original or Supplemental Proposal. Indeed, EPA cites no legal authority and provides no legal analysis for any aspect of the proposed well closure standards. Such an explanation is needed for such a key and novel aspect of this proposed rule so that interested parties have the opportunity to formulate and submit comments on EPA's legal rationale. CAA § 307(d)(3). The final rule will be procedurally deficient if EPA does not cure this problem.

Lastly, EPA provides little new evidence or arguments in the Supplemental Proposal as to why well closure standards are warranted. EPA appears to rely on the more extensive discussion provided in the original proposal. Notably, that discussion focuses on "abandoned wells" (i.e., "oil or natural gas wells that have been taken out of production, which may include a wide range of non-producing wells") "that are not plugged or are plugged ineffectively." (86 FR 63240). The discussion particularly targets "orphan wells" – i.e., those that have been abandoned and for which "there is no responsible owner." *Id*. EPA explains that the proposed well closure standards constitute a "potential strateg[y] to reduce emissions from these sources." *Id*. at 63241.

EPA explains in passing that states and other federal government agencies regulate well closures and have programs to address abandoned and orphan wells. Yet EPA does not conduct an in-depth assessment of these programs or make any attempt to distinguish how much of the perceived problem with abandoned or orphan wells relates to wells that pre-date the current federal and state programs versus wells that are regulated by such programs. In other words, EPA asserts that well closure standards are needed to address the problem of emissions from abandoned or orphan wells but does not determine that current state and federal programs are somehow deficient and, therefore, need to be supplemented by EPA standards going forward.

If EPA had delved more deeply into the current state of affairs, it would have seen that industry, states, and other federal government agencies are making great progress in addressing abandoned and orphaned wells. For example, the federal Bureau of Land Management highlights on its website its extensive regulatory and non-regulatory efforts to address orphan wells, including the hundreds of millions of dollars allocated by Congress in

[101] Comment 10.1.1 on page 40 in EPA-HQ-OAR-2021-0317-0808

the recent "Bipartisan Infrastructure Law" to support tribal, state, and federal efforts in this area. EPA does not even mention the Bipartisan Infrastructure Law in the original or Supplemental Proposals.

Before finalizing the proposed well closure standards, EPA needs to consider more closely the current regulatory landscape, the extensive non-regulatory measures focused on abandoned and orphaned wells, and the expansive voluntary efforts by industry to address this important issue. Those factors are critical to understanding whether EPA rules are needed and, if so, how they should be designed and implemented.

12.9 The Supplemental Proposal would impose unreasonable, impractical, and unduly burdensome certification requirements.

The applicability of several elements of the proposed rule depends on a certification of technical infeasibility that must be executed by a professional engineer or other qualified individual. Examples include the use of an emissions control device to handle associated gas (see, e.g., proposed § 60.5377b(b)(2)), the continued use of pneumatic pumps driven by natural gas (see, e.g., § 60.5393b(c)), and the use of emitting gas well unloading methods (see, e.g., §60.5376b(c)(2)(ii)(B)(2)). EPA imposes these certification requirements out of concern about the possible "abuse" of these provisions such that they might open a "loophole" in the regulations (87 FR 74776). EPA stresses that it, "wants to make it clear that in the case that such a certification is determined by the Agency to be fraudulent, or significantly flawed, not only will the owner or operator of the affected facility be in violation of the standards, but the person that makes the certification will also be subject to civil and potentially criminal penalties." *Id*. Thus, the proposal raises the serious prospect of individual, personal liability, not only for fraudulent certification, but also for technically erroneous (i.e., "significantly flawed") certifications.

As we discussed in our comments on the original proposal, we support these opt out provisions as a practical matter. We agree that non-emitting measures and methods should be used where they are technically feasible and cost effective. But EPA rightly understands that non-emitting approaches are not always practicable and that imposing an absolute requirement would constitute an unwarranted prohibition on necessary operations, such as liquids unloading, in many situations. The proposed alternative measures are a common-sense solution.

But our comments on the original proposal also expressed the concern that EPA has not asserted an adequate legal basis for identifying non-emitting techniques as BSER and establishing them as a standard, but at the same time creating opt outs. We pointed out that the need to allow for technical infeasibility exceptions to the proposed non-emitting standards indicates that the non-emitting standards are not permissible under CAA §111 because non-emitting standards are not "adequately demonstrated" if opt outs are needed to make them feasible and workable.

We reiterate those concerns about the legal basis for EPA's opt-out approach because onerous and potentially punitive certification requirements make the opt out approach even more legally tenuous. To begin, such certification requirements will significantly limit the situations where an opt out can be employed. As a result, what otherwise might be a reasonably viable alternative to an unworkable zero-emissions standard is unnecessarily complicated by strict certification requirements tied to an undefined standard that will be difficult to apply and limit the usefulness of the alternative. That heightens the concern that creating an opt out is unlawful circumvention of the obligation to demonstrate that BSER and the corresponding standards of performance are adequately demonstrated and cost effective.

Moreover, the proposed certification requirements are unreasonably onerous because, in each case, the certifying individual must essentially prove a negative – that the otherwise applicable zero-emissions approaches are "technically infeasible." There is no definition of technical infeasibility in the proposed rules, but the words could be construed as setting an exceedingly high bar, such that a given non-emitting technique is "infeasible" based solely on a technical assessment of whether it can theoretically be physically applied in the given situation. So, for example, that might require a non-emitting technology to be applied because it is technically theoretically possible, even though it would be inordinately expensive. This outcome would not be lawful because it would violate the statutory requirement that BSER and the corresponding standard of performance must be cost effective.

And, in any event, a "technical infeasibility" standard allows for second guessing by regulators or citizen enforcers, which invites a "battle of the experts" in potential enforcement actions. All of this diminishes the possibility that the opts outs can be implemented with reasonable certainty.

Lastly, the express threat of possible personal liability on the part of certifiers surely will limit the number of individuals willing to make the needed certifications, particularly in light of the uncertainties described above about what will be needed as a practical matter to demonstrate "technical infeasibility." The clear opportunity and possibility of second guessing will be further material disincentives.

We provide here three recommended solutions to these problems. First, rather than creating opt outs that require case-specific certification, EPA should establish the opt outs in the final regulation as regulatory alternatives that may be employed if specified criteria in the rule are met. This is the usual method of prescribing standards of performance and regulatory compliance alternatives, and it would not be difficult for EPA to structure the rule in this fashion.

Second, as explained above, one of the legal flaws in EPA's opt-out scheme is that technical feasibility is the only governing criterion. The cost of implementing the default zero-emitting standard is not a consideration. As a result, the proposed opt-out approach unlawfully evades the obligation that cost must be considered in prescribing CAA § 111 standards of performance. This flaw is easily cured by including cost as a consideration in implementing the opt-out provisions.

Third, if EPA retains the requirement for case-specific certifications, EPA should revise the required certification. The proposed regulatory text of each certification includes the following sentence: "Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete." See, e.g., § 60.5377b(b)(2). This should be revised to specify that the certification is based on "reasonably inquiry," as is required for certifications under the Title V operating permit program. The revised certification could read as follows: "Based on reasonable inquiry, including application of my professional knowledge and experience and inquiry of personnel involved in the assessment, …." A "reasonable inquiry" standard would not shield a certifier from outright fraud but would provide more latitude for reasonable differences of opinion as to technical infeasibility.

12.10 EPA should not define and impose practical enforceability requirements without first developing a consistent approach for all EPA programs.

In the original proposal, EPA proposed "to include a definition for a 'legally and practicably enforceable limit' as it relates to limits used by owners and operators to determine the potential for VOC emissions from storage vessels that would otherwise be affected facilities under these rules" (86 FR 63201). EPA explained that "[t]he intent of this proposed definition is to provide clarity to owners and operators claiming the storage vessel is not an affected facility in the Oil and Gas NSPS due to legally and practicably enforceable limits that limit their potential VOC emissions below 6 tpy." *Id*.

In our comments on that proposal, we urged EPA to defer final action on the proposed definition until such time as the Agency undertakes a broad-based rule that would provide a single, consistent approach across all affected CAA programs. Such an approach would prevent potential inconsistencies among the various CAA programs (e.g., an effective emissions limit used to avoid major New Source Review (NSR) permitting might, at the same time, not be effective for purposes of the OOOOb and/or EG OOOOc storage vessel standards); would avoid the possible implication that the "effectiveness" criteria established under EG OOOOc should be applied under other CAA programs (i.e., how can an emission limit be both effective and not effective at the same time), and allow EPA to establish reasonable transition rules so that affected sources and states have time to revise existing emissions limitations as needed to meet the new effectiveness criteria.

In addition, few existing sources have express emissions limitations for methane or GHGs. Yet, EPA has newly proposed a 20 tpy methane applicability trigger for the Subpart OOOOb and OOOOc storage vessel standards (in addition to the 6 tpy VOC trigger) (87 FR 74800). As a result, many potentially affected/designated facilities likely will seek to rely on VOC emissions limitations as a surrogate for methane emissions. The use of surrogates in establishing effective potential to emit (PTE) limits is another cross-cutting issue for which EPA should establish a unitary CAA approach rather than the proposed piecemeal, rule-by-rule approach.

We raise these issues again because EPA recently announced its intention to issue national guidance on establishing effective limits on potential to emit.[102] That effort appears to be driven by a July 2021 report from the EPA Inspector General that criticized the Office of Air and Radiation for not responding to a series of 1990's era D.C. Circuit decision that vacated or remanded the then "federal enforceability" criteria that applied across EPA's CAA regulatory programs.[103] EPA intends to issue national guidance by October 2023.

EPA's announced plan to establish national rules for effective limits on PTE and to do so in the relative near future lends strong additional support to our request that EPA should not address these issues in a premature and piecemeal fashion in the EG OOOOc rule.

13.0 Other General Comments

13.1 Due to the unreasonably short duration of the comment period for the Supplemental Proposal, API has been unable to respond to all of EPA's comment solicitations.

The proposed NSPS OOOOb and EG OOOOc are both complex rules that will apply to hundreds of thousands of facilities not previously subject to regulation under CAA. Because of the wide variety of conditions faced by these facilities, and the novel nature of a first ever existing source rule, many stakeholders requested an extension of the comment period in order to provide the agency with well-developed information necessary to promulgate an environmentally protective, technically feasible, and cost-effective rule. Concurrent with this rulemaking there are additional and overlapping regulatory developments on this subject matter including the Inflation Reduction Act Methane Emissions Reduction Program, EPA's Redesignation of Portions of the Permian Basin for the 2015 Ozone

[102] *NAAQS, Regional Haze & Permit Program Implementation Updates*, Presentation by Scott Mathias, Director Air Quality Policy Division, OAQPS, to AAPCA Fall Meeting (Sept. 29, 2022).

[103] *EPA Should Conduct More Oversight of Synthetic-Minor-Source Permitting to Assure Permits Adhere to EPA Guidance, Report No. 21-P-0175*, memorandum from Sean W. O'Donnell to Joseph Goffman (July 8, 2021) at 17.

National Ambient Air Quality Standards, EPA's Proposed Updates to the National Ambient Air Quality Standards for PM and the Bureau of Land Management's proposed Waste Prevention Rule that all must be reviewed in accordance with the overlapping aspects of these various actions.

To provide a complete set of comments on a rulemaking as broad, impactful, precedent setting, and complex as proposed within NSPS OOOOb and EG OOOOc, API requested an additional 60 days to gather information and submit comments. Not only did EPA decline API's and other stakeholders' reasonable request for a 60-day extension of the comment period, EPA did not grant even an additional two weeks as the Agency did for the initial proposal[104], which was smaller than the Supplemental Proposal. As we have stated in Comment 12.1, we recognize that every administration has the right to set and implement its regulatory agenda. Nevertheless, that this Administration would expedite issuance of the original proposed rule to align with COP26[105], delay issuance of the Supplemental Proposal to align with COP27[106], and then deny the request of pertinent stakeholders to have adequate time to provide fully-informed feedback to EPA, undermines this Administration's stated goals of reducing emissions in the service of political optics. API has developed as complete a set of comments provided herein as time has allowed. However, much of the information EPA requested, as well as additional information API wanted to provide, is not included herein due to the arbitrary and unnecessarily imposed timing constraints of the comment period for the Supplemental Proposal. We restate our industry's shared goal with EPA of reducing emissions from oil and natural gas operations across the value chain. We remain concerned that this Administration will rush to the completion of a final rule that is not cost-effective, technically feasible, or legally sound. We strongly encourage EPA to adopt the recommendations in our comments to enable the final rule to meet these critically important criteria.

13.2 EPA should reduce burden associated with the collective recordkeeping and reporting requirements.

Proposed NSPS OOOOb and EG OOOOc include onerous recordkeeping and reporting that exceed typical levels of compliance assurance and are a significant cost to operators to track and maintain. EPA should continue to focus on having operators track the most necessary information to obtain assurance.

In this proposal,

- EPA increased the recordkeeping and reporting requirements without adequately justifying increased costs with respect to the administrative burden these proposed changes would require, including numerous technical demonstrations and engineering statements. Increased costs associated with administrative burden are disproportional to benefit – because benefit is marginal when compared to other mechanisms that are already in place and proposed elsewhere in this rulemaking that focus on necessary information to assist in ensuring compliance.
- EPA continues to ignore the scale of affected/designated facilities that will become subject to these provisions over time, which is well over the tens of thousands.
- EPA has included reporting requirements that are outside the Agency's jurisdiction in requiring details on well ownership transfers.

[104] https://www.federalregister.gov/documents/2021/12/17/2021-27312/standards-of-performance-for-new-reconstructed-and-modified-sources-and-emissions-guidelines-for
[105] https://www.epa.gov/newsreleases/us-sharply-cut-methane-pollution-threatens-climate-and-public-health
[106] https://www.epa.gov/newsreleases/biden-harris-administration-strengthens-proposal-cut-methane-pollution-protect

API recognizes that it is appropriate to maintain sufficient records to demonstrate compliance. However, it is API's view that it is excessive to require such a significant level of detail to be both documented and submitted for all of the affected/designated facilities in this proposal. EPA should simplify the recordkeeping and reporting requirements to those that assure compliance without additional administrative burden. Only elements needed for compliance assurance should be requested within the annual report as supporting records retained by companies can be made available upon request from the Agency.

API has provided some initial comments on certain recordkeeping and reporting aspects of proposed NSPS OOOOb and EG OOOOc throughout this comment letter, but due to the short comment period have not had adequate time to fully assess the impact of what EPA has proposed. Some initial thoughts on the proposed draft reporting form template include the following:

- One initial concern is that many companies do not allow the use of workbooks containing macros as a cybersecurity measure and the current draft workbook contains macros. If the form is dependent on the macro formatting, this may be an issue for some reporters using the form.
- We do not support the reporting of additional information related to well transfers (including name, phone number, email, and mailing address) as proposed §60.5420b(b)(1)(v).
- The control device and closed vent system tabs are set up where multiple affected facilities that route to a single control device or through the same closed vent system cannot be identified on a single row. This will result in redundant and duplicate information being reported.
- Certain selection options for "Deviation Category" the "Description of Deviation" and "Type of Deviation" cells are automatically blacked out and do not allow an operator to provide additional context. The operator should have the ability to add free text in these areas and provide additional information as needed.

We will continue to review the recordkeeping and reporting requirements proposed within these rules along with the draft reporting form (EPA-HQ-OAR-2021-0317-1536_content) and continue to provide EPA feedback on ways to streamline the template.

13.2.1 CEDRI System Concerns

Our members have concerns with the practical implications with reporting through CEDRI when/if there is a system outage. Specifically, we request EPA evaluate the following language as proposed under NSPS OOOOb and EG OOOOc, but note these concerns also apply to NSPS OOOOa:

- §60.5420b(e)(2): We believe this paragraph should be removed or, at a minimum, be inclusive of the compliance end period and the compliance submittal date. Staff scheduling submittal may choose to do so prior to 5 days before the compliance submittal date. If EPA is requiring the use of the reporting form within CEDRI, then it should not be in deviation on the operator in any circumstance.

- §60.5420b(e)(4): The requirement for the reporter to notify EPA immediately upon discovery of an outage is unduly burdensome for the reporter. EPA should manage the reporting system and notify registered users of an outage.

- §60.5420b(e)(5)(iii): It is unclear what EPA is intending for a reporter to include as far as "a description of measure taken to minimize the delay in reporting". EPA should be taking action to minimize the delay in reporting if there is a CEDRI system outage. The regulated entity has no additional recourse in this instance.

- §60.5420b(e)(6): System outage should warrant automatic claims to those submitting reports. Operators should not be penalized when the only method for submittal is not available and out of their control.

- EPA should implement a secure process, similar to EPA's e-GGRT program, to prevent those who are not owners or operators or are authorized representatives of an affected facility from submitting to CEDRI for any affected facility.

13.3 EPA should clarify its statements regarding the Crude Oil and Natural Gas source category and the extent of crude oil operations for purposes of this rulemaking.

Within proposed NSPS OOOOb and EG OOOOc the Crude Oil and Natural Gas source category is defined consistent with historical definitions finalized in NSPS OOOO and NSPS OOOOa:

> *Crude oil and natural gas source category means:*
>
> *(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and*
> *(2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the local distribution company custody transfer station.*

In footnote 301 (87 FR 74833), EPA states:

> [301] "*For purposes of the November 2021 proposal and this supplemental proposed rulemaking, for crude oil, the EPA's focus is on operations from the well to the point of custody transfer at a petroleum refinery, while for natural gas, the focus is on all operations from the well to the local distribution company custody transfer station commonly referred to as the ''city-gate''.*

We do not believe that EPA intends to regulate crude oil operations beyond the point of custody transfer from a well to a transmission pipeline and we request that EPA clarify and correct these statements in the final rule to align with the definition of the source category as proposed.

13.4 Applicability for Inactive sites and Reactivation of Inactive Sites

Many sites may periodically shut-in or depressurize all or partial equipment, where the entire site might be inactive or certain equipment might be inactive. We believe this is an appropriate criterion for exemption for all affected or designated facilities under NSPS OOOOb and EG OOOOc. At a minimum, we seek clarification as the status of inactive facilities and depressurized equipment as they pertain specifically to fugitive emission monitoring (Comment 2.5) and the retrofit of pneumatic controller and pneumatic pump provisions under EG OOOOc. We do not believe it is EPA's intent to require facilities that are not in active operations to retrofit the pneumatic controllers at the facility to non-emitting nor would it be appropriate for equipment that has been depressurized and inactive to be screened for fugitive emission monitoring.

Additionally, some inactive sites or equipment might be put back into service, where the applicability under NSPS OOOOb versus EG OOOOc must be delineated. One example is under *Pennsylvania's § 127.11a. Reactivation of sources*, which allows: *"a source which has been out of operation or production for at least 1 year but less than or equal to 5 years may be reactivated and will not be considered a new source if the following conditions are satisfied…".* EPA already has included language addressing this concept as it pertains to storage vessels. We believe EPA should extend this concept to all affected and designated facilities. If a site that was inactive were to become active, there should be adequate time for the site to comply with the provisions within EG OOOOc.

13.5 The Social Cost of Greenhouse Gases

API shares the Administration's goal of reducing economy wide GHG emissions. And while API further appreciates EPA's decision to accept comments specifically on the EPA's SC-GHG Report, we have a number of questions and concerns about EPA's unilateral development of SC-GHG estimates, the anticipated role of these new estimates in Agency rulemaking, and the SC-GHG Report's apparent inconsistency with the Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the Interagency Working Group ("IWG").

In Attachment B, API explains how EPA's development of the SC-GHG Report appears inconsistent with the approach to which the Biden Administration committed in E.O. 13990 and other administrative directives, and why those inconsistencies call into question the rationality, defensibility, and durability of both EPA's agency-specific estimates as well as the administration-wide estimates developed by the IWG. We also describe how EPA's SC-GHG Report contains almost no discussion reflecting that EPA examined reasonable alternatives in scientific literature to its various technical choices, reflects no meaningful consideration of relevant analyses and recommendations previously submitted by API and others, and therefore appears to be based on a selective and incomplete application of important substantive and procedural recommendations, including the full suite of recommendations that the National Academies of Science, Engineering, and Medicine provided to the IWG.

13.6 Cross Reference and other Minor Clarifications

Below are some cross reference and other typos we have identified within the prosed NSPS OOOOb and EG OOOOc regulatory text.

- Subpart OOOOc makes eight references to a §60.5933c, one of which gives its title as "Alternative Means of Emissions Limitation." However, there is no actual section in EG OOOOc with that number or title.
- §60.5413b(d)(11)(iii): *A manufacturer must demonstrate a destruction efficiency of at least 95.0 percent for THC, as propane. A control device model that demonstrates a destruction efficiency of 95.0 percent for THC, as propane, will meet the control requirement for 95.0 percent destruction of VOC <u>and methane</u> (if applicable) required under this subpart.*
- §60.5370b(a)(1)(iii) refers to §60.5385b(a)(3), which does not appear to exist.
- The additional citations should be checked for correct cross referencing: §60.5420b(c)(2)(ii)(B), §60.5410b(f)(2)(iv)(B), §60.5420b(b)(10)(vi), and §60.5420b(c)(12).

Attachment A

Responses to EPA Solicited Comments for Use of Optical Gas Imaging in Leak Detection

Responses to EPA Solicited Comments for Use of Optical Gas Imaging (OGI) in Leak Detection

VI.C OGI Monitoring Requirements – Specifying Dwell Time to Account for Scene Complexity

[T]he EPA is soliciting comment on how dwell time could be based on the scene while still accounting for the differences in the complexity of scenes or ways to create bins for “simple” and “complex” scenes.

Response: *The most intuitive method to differentiate between “simple” and “complex” scenes would be to base it on the number of components being imaged and viewing distance. An example of a “simple” scene would be a scene of 20-25 components viewed at a distance of < 15-25 feet. This approach offers a high probability of leak detection by a technician. The high probability of detection is supported by existing operating envelope testing conducted by camera manufacturers which demonstrated consistent image detection at these distances at delta-T as low as 2 degrees C. Moreover, the number of components being limited to 25 in a simple scene means a technician is likely to have great discernment or granularity of the image which improves their ability to detect image of a leak. “Complex” scenes would be when there are greater than 25 components or viewing distances greater than 25 feet.*

VI.C OGI Monitoring Requirements – Ensuring OGI Camera Operators Survey a Scene is Adequate Without Specifying Dwell Time

The EPA is also soliciting comment on ways to similarly achieve the goal of ensuring that OGI camera operators survey a scene for an adequate amount of time to ensure there are no leaks from any components in the field of view without specifying a dwell time.

Response: *The “simple” scene criteria offered previously ensures that a technician has optimum image detection consistent with operating envelopes of camera. Specifying a dwell time for these types of scenes would be irrelevant as the technician will be looking closely at the scene in their viewfinder looking to detect any imagery. Placing a constraint of dwell time would complicate their efforts and distract from their efforts at viewing the scene. A well-trained technician who consistently passes their performance audits will be expected to make a diligent and careful survey of the components in the scene.*

VI.C OGI Camera Operators – Performance Audit Frequency

The EPA believes that it is important to verify the performance of all OGI camera operators, even the most experienced operators, on an ongoing basis. Nevertheless, the EPA is requesting comment on whether there should be a reduced performance audit frequency for certain OGI camera operators, and if so, who should qualify for a reduced frequency, what the reduced frequency should be, and the basis for the reduced frequency.

Response: *The performance audit requirements can become a significant time-consuming activity for site(s) with large numbers of technicians in their survey crew. In the initial stages of OGI monitoring implementation, more frequent performance audits have a key role to play in ensuring technician efficacy. However, technician monitoring proficiency will increase quickly over time as their monitoring experience and time doing surveys increases. The* *agency's reference to the MTEC study clearly documented this to be the case. As such, for technicians who consistently have satisfactory performance audits, it is appropriate to extend the interval between audits for those technicians. A simple methodology to do so is to follow a "skip period" approach to performance audits. For technicians who pass four consecutive quarterly performance audits, then their audit interval should be extended to semi-annual. For technicians who pass two consecutive semi-annual performance audits, then their audit interval should be extended to annual. If a technician does not pass a semi-annual or annual audit or conduct a monitoring survey during the previous 12 months per Section 10.5 of Appendix K, then quarterly performance audits would be restarted.*

VI.C OGI Surveys – Length of Survey Period

[T]he EPA has heard anecdotally that this may have more to do with the number of hours the OGI camera operator has surveyed during the day, such that it is more appropriate to limit the hours of surveying per day than it is to mandate rest breaks at a set frequency. The EPA is seeking any empirical data on the topic of the necessity of rest breaks when conducting OGI surveys or the link between operator performance and length of survey period.

***Response**: Fatigue potential is directly related to duration of continuous viewing through the camera and holding the camera in viewing position for extended periods. OSHA already has appropriate guidelines for ergonomics in the work place which include eye strain etc. Sites already have rigorous guidelines and safeguards for ergonomics, heat stress, etc. EPA should not attempt to develop regulatory standards for technician rest breaks. The agency should simply state that the monitoring plan incorporate appropriate rest breaks for technicians and simply state a rest break is required if the technician has been conducting a continuous viewing through OGI camera for 20 minutes or more. It is important to note that technicians would rarely have a 20-minute continuous viewing scenario. The primary monitoring method is to survey a component or scene for 1-2 minutes and then move to next location. When moving viewing locations, the technician would lower the camera to a neutral position and not be "viewing" though camera.*

VI.C Adequate Delta-T – OGI Camera

The EPA is proposing that the monitoring plan must describe how the operator will ensure an adequate delta-T is present to view potential gaseous emissions, e.g., using a delta-T check function built into the features of the OGI camera or using a background temperature reading in the OGI camera field of view. […] [A] commenter stated guidance should be added for operators who are using a background temperature reading in the OGI camera field of view. The EPA is requesting comment on ways that an OGI camera operator can ensure an adequate delta-T exists during monitoring surveys for cameras that do not have a built-in delta-T check function.

***Response:** The simplest and most straightforward way for a technician to ensure adequate delta-T is to utilize the camera's function to display the temperature of the equipment or background behind the component being surveyed for leaks. Most, if not all, OGI cameras in use for leak surveys have this ability currently. As such, if the technician knows the ambient temperature, then it is a simple step to add/subtract the background from ambient to determine delta-T. The elegance of this approach is it allows the technician to adjust their angles or take additional steps in* *real-time during the survey process to ensure the delta-T of the operating envelope is maintained during any survey step.*

VI.C Daily OGI Camera Demonstration Prior to Imaging to Determine Maximum Distance for Imaging

[O]ne commenter suggested that instead of having different operating envelopes for different situations and having to decide which envelope to use, the OGI camera operator should conduct a daily camera demonstration each day prior to imaging to determine the maximum distance at which the OGI camera operator should image for that day. The EPA believes that this type of determination would be more difficult and costly than creating an operating envelope, as it would require OGI camera operators to have necessary gas supplies on hand and take time to do this determination daily, or potentially multiple times a day. Nevertheless, the EPA is requesting comment on this suggestion, as well as how such a demonstration could be used if conditions on the site change throughout the day, at what point would the changed conditions necessitate repeating the demonstration, and how changes in the background in different areas of the site (such as to affect the delta-T) would be factored into such a demonstration.

Response: *Use of pre-defined operating envelopes through testing as prescribed in Section 8.0 of Appendix K is a highly useful and pragmatic methodology to determine detection capability and restrictions for monitoring surveys. It is expected that most OGI camera manufacturers plan to have completed the development of the operating envelopes after Appendix K is promulgated. However, the option for a site to do a daily or site-specific distance check utilizing a known gas concentration and flow rate at actual metrological conditions prior to conducting monitoring surveys should remain an option for a site.*

The reasons for retaining an option for a daily distance check are two-fold. First, a site may be conducting monitoring surveys with an OGI camera that does not yet have established operating envelopes. This could occur for a site using an OGI camera new to market or simply that initial monitoring surveys are planned to improve emissions reductions potential prior to the manufacturer publishing operating envelopes. Second, a site may believe that monitoring conditions for a given survey or site are unique with respect to pre-defined operating envelopes and want to ensure that the guidance on delta T and distance are appropriately set for the technicians' survey task. It is logical to include this option in Appendix K.

With respect to changing conditions, technicians should already be trained in recognition of factors (e.g., meteorological conditions) which would impact the leak detection capability. When conditions are significantly different then the technicians should switch to another operating envelope or conduct another distance check verification. This is already adequately addressed in Section 9.2.3. language.

Comments for Appendix K

"Appendix K. The EPA is not including a requirement to conduct OGI monitoring according to the proposed appendix K for well sites or centralized production facilities, as was proposed in the November 2021 proposal. Instead, the EPA is proposing to require OGI surveys following the procedures specified in the proposed regulatory text for NSPS OOOOb (at 40 CFR 60.5397b) or according to EPA Method 21." [FR74723]

Comment: *This is the correct decision and recognizes the fundamental differences between upstream production and other industry sectors.*

Definition of fugitive emissions component. The EPA is proposing specific revisions to the definition of fugitive emissions component that was included in the November 2021 proposal. First, the EPA is proposing to add yard piping as one of the specifically enumerated components in the definition of a fugitive emissions component. While not common, pipes can experience cracks or holes, which can lead to fugitive emissions. The EPA is proposing to include yard piping in the definition of fugitive emissions component to ensure that when fugitive emissions are found from the pipe itself the necessary repairs are completed accordingly. [FR 74723]

Comment*: Cracks or holes in piping have never been considered fugitive components in any other rule for Leak Detection and Repair (LDAR) in any industry sector by the agency. These types of events represent potential loss of containment and are already repaired or corrected per industry practice and code.*

Definition of fugitive emissions component. Based on changes made and discussed under section IV.A.1.a.ii of this preamble, the EPA is proposing to define fugitive emissions component as any component that has the potential to emit fugitive emissions of methane or VOC at a well site, centralized production facility, or compressor station, including valves, connectors, pressure relief devices, open-ended lines, flanges, covers and CVS not subject to 40 CFR 60.5411b, thief hatches or other openings on a storage vessel not subject to 40 CFR 60.5395b, compressors, instruments, meters, and yard piping. [FR 74736]

Comment*: The agency has consistently set VOC and VHAP content criteria in all previous fugitive emissions component monitoring requirements. These thresholds were typically defined as "in VOC service" which specified 10% VOC as the appropriate level where the emission reduction potential from leaking components was cost-beneficial. The agency stated that no data had been offered to support a one percent methane threshold and that produced water and wastewater streams can be significant sources of emissions. In the cited reference document ''Measurement of Produced Water Air Emissions from Crude Oil and Natural Gas Operations.'' Final Report. California Air Resources Board. May 2020, it stated that concentrations of compounds in the liquid phase were the best prediction of expected air emissions. This is correct and makes the point of industry comment to set a definitive threshold where cost beneficial emissions can be expected. Emissions potential is directly related to the concentration of methane and/or hydrocarbon in the process stream. Small concentrations of VOC (<10 wt%) and methane do not represent significant emissions potential; a fact that the agency has recognized in multiple updates to fugitive emission regulations.*

The apparent agency approach was simply to set the threshold at a single molecule which is inconsistent with decades of regulatory approaches to fugitive emission control methodology. As the relative proportion of VOC or methane in the given component goes down, the cost effectiveness of LDAR gets increasingly less favorable until, when the amount of VOC or methane approaches zero, the cost effectiveness value approaches infinity. The agency must consider cost for BSER determination. The content threshold used within the agency's cost effectiveness analysis is unclear. Either the agency used the traditional threshold content approach for estimating the potential regulated component inventory or it has overstated the cost effectiveness through the overstatement of emissions potential from components with very small methane and VOC contents.

In the preamble, the agency stated that industry had offered no empirical data to not establish an appropriate threshold. The agency has not demonstrated why a 1% methane and 10% VOC threshold are not appropriate, or how meaningful and cost-effective emission reductions are achieved at levels below those proposed by industry. This demonstration was not met by the agency in their definition of "potential to emit" and therefore the agency has not justified their decision. The recommendation to set the definition to include the VOC threshold at 10% and methane at 1% is an appropriate good faith effort by industry to reduce emissions.

EPA proposed that where a CVS is used to route emissions from an affected facility, the owner or operator would demonstrate there are no detectable emissions (NDE) from the covers and CVS through OGI or EPA Method 21 monitoring conducted during the fugitive emissions survey. Where emissions are detected, the emissions would be considered a violation of the NDE standard and thus a deviation. [FR 74804]

Comment: *The agency has a long history and regulatory precedents for pressure relief devices in both NSPS and NESHAP standards. These standards mandate that closed-vent systems are monitored annually with 5/15-day repair criteria. Routine AVO monitoring rounds by unit operators is also a standard work practice. CVS piping and components have been consistently found to have low leak percentages which makes sense when one considers that most of these components remained in a fixed configuration (i.e.., car-sealed open) and there is little to no operating changes of the FECs.*

The agency proposed action to make any emissions detection a violation is also a departure from historical leak detection and repair regulatory standards. EPA stated that their logic was that the NDE requirement was an emission standard and as such it has to be a violation even if repair provisions were allowed. This is an inappropriate regulatory approach since the NDE requirement should be considered a work practice standard rather than a numerical emissions standard. The CVS and control device requirements are sufficient to ensure that NDE operating conditions are the norm. The fact that the agency has prescribed monitoring survey requirements indicates the agency knows this paradigm to be true. The most important aspect of leak detection is routine surveillance of components and piping at appropriate intervals with prompt repair to stop the leak. The current 5-15 day repair timelines achieves this fundamental precept of LDAR, and making any leak detection a violation is an unnecessary addition to the requirements that does not expedite repairs or provide environmental benefits. Violations occur when repairs are not completed per requirements and/or routine monitoring is not conducted on-time or efficaciously.

In addition to this bimonthly OGI monitoring requirement, the EPA is also proposing to require OGI monitoring of each pressure relief device after each pressure release, as it is important to ensure the pressure relief device has reseated and is not allowing emissions to vent to the atmosphere. The EPA is soliciting comment on this change from a no detectable emissions standard to a bimonthly monitoring requirement. Where the EPA Method 21 option is used, we are proposing quarterly monitoring of the pressure relief device in addition of monitoring after each pressure relief. A leak is defined as an instrument reading of 500 ppm or greater when using EPA Method 21. [FR 74807]

Comment: *The agency has a long history and regulatory precedents for pressure relief devices in both NSPS and NESHAP standards. The most recent and stringent precedent for PRDs is found in the Part 63 Subpart CC which* *requires monitoring post-release to verify re-seating of PRD. The agency has consistently followed this approach in other RTR evaluations which makes this approach inconsistent with agency's technical analysis.*

Not requiring routine monitoring of PRDs makes sense if one considers that if PRDs are properly seated then they are assumed to be in non-venting condition. Monitoring post-release is sufficient to ensure the emission standard is maintained.

EPA is proposing a requirement to monitor the CVS at the same frequency (i.e., bimonthly OGI in accordance with appendix K or quarterly EPA Method 21) as other equipment in the process unit and to repair any leaks identified during the routine monitoring. [FR 74808]

Comment: *In existing and recently revised NSPS and NESHAP standards for closed vent systems and control devices, the agency has prescribed initial inspection and on-going annual AVO inspections. The agency indicated there would be no cost to do these surveys, but that is incorrect. The monitoring survey routes would have to be expanded to include the CVS piping/ductwork sections which increases labor costs based on increased technician field survey time.*

Appendix K

EPA is proposing to revise the scope and applicability for appendix K to remove the sector applicability and to base the applicability on being able to image most of the compounds in the gaseous emissions from the process equipment. The EPA is retaining the requirement that appendix K does not on its own apply to anyone but must be referenced by a subpart before it would apply. [FR 74837] (App K VI.B.1)

1.3 Applicability. This protocol is applicable to facilities when specified in a referencing subpart. This protocol is intended to help determine the presence and location of leaks and is not currently applicable for use in direct emission rate measurements from sources

Comment: *This change in applicability is the correct approach. However, consistent with previously submitted comments on the proposed rulemaking, we recommend EPA proceed expeditiously to amend part 63 subpart CC (RMACT 1) to allow use of OGI technology and Appendix K as an alternative to Method 21 for refineries. In the recent Refinery Sector Rulemaking, EPA proposed allowing for use of OGI as an alternative to Method 21, but did not finalize that proposal because "we have not yet proposed appendix K."[107] Adding OGI as an alternative to RMACT 1 would significantly reduce the refinery and Agency resources associated with preparing and reviewing Alternative Method of Emission Limitation or Alternative Monitoring requests to allow OGI for those facilities and allow refineries to take advantage of the improvements inherent in Appendix K versus the currently available leak detection and repair (LDAR) Alternative Work Practice (AWP) in Part 60 Subpart A (§60.18(g), (h) and (i)). Moreover, it would be important for EPA to amend other Part 60 and 63 standards to make Appendix K an option for industry sectors beyond refineries.*

[107] 80 *Fed. Reg.* 75191 (December 1, 2015)

6.1.2 The OGI camera must be capable of detecting (or producing a detectable image of) methane emissions of 17 grams per hour (g/hr) and either butane emissions of 5.0 g/hr or propane emissions of 18 g/hr at a viewing distance of 2 meters and a delta-T of 5 °Celsius (C) in an environment of calm wind conditions around 1 meter per second (m/s) or less, unless the referencing subpart provides detection rates for a different compound(s) for that subpart.

Comment: *The response factor for butane and propane are almost identical, why has the agency selected lower mass rate criteria for butane? It seems inconsistent with the language in Section 1.2 which allows for the average response factor approach with respect to propane.*

9.3 The site must conduct monitoring surveys using a methodology that ensures that all the components regulated by the referencing subpart within the unit or area are monitored. This must be achieved using one of the following three approaches or a combination of these approaches. The approach(es) chosen and how the approach(es) will be implemented must be described in the monitoring plan

Comment: *The language provided in the Appendix K revisions for monitoring survey methodology provides additional flexibility consistent with industry comments. However, as written, the methodology is limited to just three options without any ability for a site to propose an alternative. Technology and survey approaches are always being improved with new creative ideas coming to forefront all the time. For example, use of GPS in surveys is only a recent capability in the past few years. The agency should add language which allows a site to use another methodology as long as it meets the intent and capabilities of the ones currently identified. A site could propose an alternative to their delegated authority prior to use*

9.4.1 For a complex scene of components, the operator must divide the scene into manageable subsections and dwell on each angle for a minimum of 2 seconds per component in the field of view (e.g., for a subsection with 5 components, the minimum dwell time would be 10 seconds). It may be necessary to reduce distance or change angles in order to reduce the number of components in the field of view

Comment: *See comments provided on "simple" and "complex" scene approaches.*

9.7.2 A full video of the monitoring survey must be recorded. The video must document the monitoring results for each piece of regulated equipment. Leaking components must be tagged for repair, and the date, time, location of each leak, and identification of the component associated with each leak must be recorded and stored with the OGI survey records.

Comment *– This language could be read to imply a full continuous video of the monitoring survey would be required which is inconsistent with the language of Section 9.7.1 where only video or still imagery of the leaks are required. This language should be deleted or clearly state that sites may elect as alternative to simply save the full continuous video versus leak imagery only.*

9.8 The monitoring plan must include a quality assurance (QA) verification video for each OGI operator at least once each monitoring day. The QA verification video must be a minimum of 5 minutes long and document the procedures the operator uses to survey (e.g., dwell times, angles, distances, backgrounds) and the camera configuration.

***Comment** – As mentioned in previous comments to Appendix K proposals, the daily QA verification video is unlikely to offer much value to a monitoring program. The most effective methodology to ensure technician monitoring efficacy is comparative monitoring via periodic performance audits. The daily quality assurance (QA) verification video requirement should be deleted.*

10.2.2.1 A minimum of 3 survey hours with OGI where trainees observe the techniques and methods of a senior OGI camera operator (see definition in Section 3.0) who reinforces the classroom training elements.

10.2.2.2 A minimum of 12 survey hours with OGI where the trainee performs the initial OGI survey with a senior OGI camera operator verifying the results by conducting a side-by-side comparative survey and providing instruction/correction where necessary.

10.2.2.3 A minimum of 15 survey hours with OGI where the trainee performs monitoring surveys independently with a senior OGI camera operator trainer present and the senior OGI camera operator providing oversight and instruction/correction to the trainee where necessary.

***Comment:** The specific hourly requirement for each survey training phase is too restrictive and does not reflect how individuals learn and master new skills. Some technicians may need more or less time in a particular phase or benefit more from side-by-side or direct observation. A more appropriate approach is to specify a total of 30 hours of field survey hours which includes direct observation, side-by-side, and independent surveys without such prescriptive hourly content. As long as the 30 hours of training surveys includes an appropriate number of components to be surveyed (e.g., 300) and a final monitoring survey test, then the proficiency will be attained and verified.*

Attachment B

Comments on the U.S. Environmental Protection Agency’s Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances

Comments on the EPA's Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances

I. INTRODUCTION

As an addendum to our comments on the U.S. Environmental Protection Agency's ("EPA's" or "the Agency's") Supplemental Notice of Proposed Rulemaking on the revised "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" ("Proposed NSPS Revision"),[108] the American Petroleum Institute ("API") respectfully submits these additional comments on EPA's "Report on the Social Cost of Greenhouse Gases: Estimates Incorporating Recent Scientific Advances" ("SC-GHG Report").[109]

API represents all segments of America's oil and natural gas industry. Our over 600 members produce, process, and distribute the majority of the nation's energy. The industry supports millions of U.S. jobs and is backed by a growing grassroots movement of millions of Americans. API was formed in 1919 as a standards-setting organization. In our first 100 years, API has developed more than 700 standards to enhance operational and environmental safety, efficiency, and sustainability. API and its members are committed to delivering solutions that reduce the risks of climate change while meeting society's growing energy needs. Addressing this dual challenge requires new approaches, new partners, new policies, and continuous innovation.

API believes that the pace of global action to reduce greenhouse gas ("GHG") emissions and effectively mitigate climate change will be determined by government policies and technology innovation. To that end, we have laid out a Climate Action Framework[110] that presents actions we are taking to accelerate technology and innovation, further mitigate GHG emissions from operations, advance cleaner fuels, drive comparable and reliable climate reporting, and, importantly, endorse a carbon price policy.

The natural gas and oil industry is essential to supporting a modern standard of living for all by ensuring that communities have access to affordable, reliable, and cleaner energy, and we are committed to working with local communities and policymakers to promote these principles across the energy sector. Our top priority remains public health and safety, and companies often have well-established policies in place for proactive community engagement and feedback aimed at fostering a culture of trust, inclusivity, and transparency. We believe that all people should be treated fairly, regardless of race, color, national origin, or income, with respect to the development, implementation, and enforcement of environmental laws, regulations, and policies.

API shares the Biden Administration's goal of reducing economy-wide GHG emissions. And while API further appreciates EPA's decision to accept comments specifically on the Agency's SC-GHG Report, we have a number of questions and concerns about EPA's unilateral development of SC-GHG estimates, the anticipated role of these new estimates in Agency rulemaking, and the SC-GHG Report's apparent inconsistency with the Biden Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the Interagency Working Group ("IWG").

[108] 87 Fed. Reg. 74,702 (Dec. 6, 2022).
[109] Docket ID No. EPA-HQ-OAR-2021-0317 (Sept. 2022).
[110] https://www.api.org/climate.

Indeed, API has for many years attempted to constructively engage the IWG in its development of SC-GHG estimates, and has submitted detailed comments on multiple previous IWG technical support documents, including the IWG's most recent "Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide Interim Estimates Under Executive Order 13990" ("Interim TSD").[111] Those comments provided the IWG constructive and actionable recommendations to improve the transparency, rationality, defensibility, and thus, durability of its estimates of the SC-GHG, and urged caution on the inherently limited utility of SC-GHG estimates. Those comments also specifically recommended that the IWG publish proposals for, and accept public comment on, the recommendations the IWG was required to provide by September 1, 2021 regarding potential applications for the SC-GHG,[112] the additional recommendations the IWG was required to provide by June 1, 2022 for revising the processes and methodologies for estimating the SC-GHG,[113] and final SC-GHG estimates the IWG was supposed to publish "no later than January 2022."[114]

Insofar as API is aware, after publishing the interim SC-GHG estimates in 2021, the IWG has not completed any of the actions required by E.O. 13990 or taken any action in response to comments and recommendations submitted by API and other parties. Moreover, notwithstanding that EPA is a key participant in the IWG, EPA's unilateral development of the revised SC-GHG estimates in the SC-GHG Report is not only inconsistent with the approach President Biden committed to in E.O. 13990, it does not appear to reflect any consideration of the comments API and others provided to the IWG.

In the detailed comments that follow, API explains how EPA's development of the SC-GHG Report appears inconsistent with the approach to which the Biden Administration committed in E.O. 13990 and other administrative directives, and why those inconsistencies call into question the rationality, defensibility, and durability of both EPA's agency-specific estimates as well as the administration-wide estimates developed by the IWG. We also describe how EPA's SC-GHG Report contains almost no discussion reflecting that EPA examined reasonable alternatives in scientific literature to its various technical choices, reflects no meaningful consideration of relevant analyses and recommendations previously submitted by API and others, and therefore appears to be based on a selective and incomplete application of important substantive and procedural recommendations, including the full suite of recommendations that the National Academies of Science, Engineering, and Medicine ("National Academies" or "NASEM") provided to the IWG.

Although API appreciates EPA's willingness to accept comments on the SC-GHG Report, consistent with the National Academies' recommendations, we believe EPA should have transparently engaged and collaborated with interested stakeholders throughout its process to revise and update each of the four modules on which the SC-GHG Report based its revised estimates, rather than postpone comment until each modules had been updated and the SC-GHG Report had been fully drafted. Given the extent of the changes encompassed in EPA's SC-GHG Report and the extensive new data and analyses on which the report purports to be based, API believes that the current 69-day comment period is insufficient for soliciting detailed feedback from informed stakeholders, particularly given that this comment period encompassed multiple holidays.

API is similarly concerned that EPA's docket for this rulemaking does not include all of the studies and data on which EPA purports to have based its SC-GHG Report, and therefore fails to provide interested parties sufficient information on which to base detailed comments. This is a particular concern in a rulemaking conducted pursuant

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[111] 86 Fed. Reg. 24,669 (May 7, 2021).
[112] *See* 86 Fed. Reg. at 24,670.
[113] *See* E.O. 13990 at Sec. (5)(b)(ii)(D) and (E).
[114] *See* E.O. 13990 at Sec. (5)(b)(ii)(B).

to the Clean Air Act ("CAA" or "the Act") because of the CAA's enhanced requirement that EPA justify rules based solely on the record it compiles and makes public at the time of the proposal.[115]

Notwithstanding the forgoing, in Section III.b. below, API raises a number of significant technical questions and concerns about EPA's data selection, framing decisions, and modeling assumptions. As noted therein, it is critical the SC-GHG Report completely and transparently explain the precise basis for each of its analytical framing decisions because the SC-GHG estimates that EPA developed using the process described in the SC-GHG Report are highly sensitive to even modest changes to one or a few model choices and judgements.

Finally, in Section III.c, API describes why, regardless of whether they are developed by the IWG or EPA alone, inherent limitations in estimates of the SC-GHG significantly constrain their utility in rulemaking. As EPA seemingly recognizes based on its apparent intent to use the SC-GHG Report in the Regulatory Impact Analysis but not as part of its assessment of the Best System of Emissions Reduction ("BSER") in the Proposed NSPS Revision itself, SC-GHG estimates may only have utility with respect to broad considerations of costs and benefits in analyses under E.O. 12866, and not in rules that require the SC-GHG to be expressed as a single value or with a narrow range of uncertainty.[116]

II. BACKGROUND

As noted in EPA's SC-GHG Report, the SC-GHG represents "the monetary value of future stream of net damages associated with adding one ton of that GHG to the atmosphere in a given year."[117] This metric, which originally attempted to estimate the social cost of only CO_2 emissions, "was explicitly designed for agency use pursuant to E.O. 12866. . ."[118] Since it was signed by President Clinton in 1993, E.O. 12866 has directed agencies to "propose or adopt a regulation only upon a reasoned determination that the benefits of the intended regulation justify its costs."[119] And when the proposed action is deemed a "significant federal action," E.O. 12866 required agencies to coordinate with OMB's Office of Information and Regulatory Affairs ("OIRA") in the development of a formal cost-benefit analysis called a Regulatory Impact Analysis ("RIA"). Thus, the SC-GHG Report characterizes the SC-GHG as "the theoretically appropriate value to use when conducting benefit-cost analyses of policies that affect GHG emissions,"[120] and consistent with that characterization, EPA purports to only rely on the SC-GHG Report in the RIA it issued in support of the Proposed NSPS Revisions.[121]

Initially, federal agencies' consideration of CO_2 emissions in RIAs was sporadic and varied significantly between agencies.[122] When agencies did consider CO_2 emissions, they utilized a variety of different methodologies that

[115] *See Sierra Club v. Costle*, 657 F.2d 298, 401 (D.C. Cir. 1981).
[116] *See* 87 Fed. Reg. at 74,713.
[117] SC-GHG Report at 4.
[118] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428. Per E.O. 12866 Sec. 1(a): "Federal agencies should promulgate only such regulations as are required by law, are necessary to interpret the law, or are made necessary by compelling public need, such as material failures of private markets to protect or improve the health and safety of the public, the environment, or the well-being of the American people. . . . Further, in choosing among alternative regulatory approaches, agencies should select those approaches that maximize net benefits (including potential economic, environmental, public health and safety, and other advantages; distributive impacts; and equity), unless a statute requires another regulatory approach."
[119] E.O. 12866 at Sec. 1(a). When the proposed action is deemed a "significant federal action," E.O. 12866 required agencies to coordinate with OMB's Office of Information and Regulatory Affairs ("OIRA") in the development of a formal cost-benefit analysis called a Regulatory Impact Analysis ("RIA"). (E.O. 12866 at Sec. 6(a)(3)(C)). A "Significant regulatory action" is "any regulatory action that is likely to result in a rule that may: (1) Have an annual effect on the economy of $100 million or more or adversely affect in a material way the economy, a sector of the economy, productivity, competition, jobs, the environment, public health or safety, or State, local, or tribal governments or communities; (2) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency; (3) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs or the rights and obligations of recipients thereof; or (4) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in [E.O. 12866]" (Sec. 3(f)).
[120] SC-GHG Report at 4.
[121] *See* 87 Fed. Reg. at 74,713.
[122] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.

resulted in a wide range of estimates, each with different ranges of uncertainty.[123] The government was consistent, however, in limiting use of these early estimates to RIAs, and in providing separate values for "domestic" and "global" impacts.[124] The government's consideration of CO_2 emissions became more frequent and consistent, however, after a 2008 Ninth Circuit decision remanded a fuel economy rule for failing to consider the potential benefit of CO_2 emission reductions, stating that "while the record shows that there is a range of values, the value of carbon emissions reduction is certainly not zero."[125] Subsequent court decisions on the necessity and method of considering CO_2 emissions for federal agency actions have been mixed.

To help federal agencies comply with E.O. 12866, "harmonize a range of different SC-CO_2 values being used across multiple Federal agencies,"[126] and "ensure consistency in how benefits are evaluated across agencies," President Obama established the IWG in 2009.[127] The IWG was tasked with developing "a transparent and defensible method, specifically designed for the rulemaking process, to quantify avoided climate change damages from reduced CO_2 emissions."[128] As such, from the beginning, the IWG's SC-GHG estimates were intended to provide consistency across federal government agencies exclusively for the development of RIAs for "significant regulatory actions" involving GHG emissions. Notably, [t]his does not apply to many routine agency actions that will produce GHG emissions."[129]

The IWG's November 2013 TSD represented the first time the IWG (through OMB) accepted comment on the SC-CO_2 estimates.[130] Although the IWG and OMB had finally agreed to accept comments, they did not provide any materials other than the most recent TSDs. Thus, comments submitted by API and others urged the IWG to select its Integrated Assessment Model ("IAM") parameters through a highly transparent, collaborative, and data-driven process because modest changes to just a few model inputs drastically changes the output of the IAMs and therefore the SC-CO_2 estimate.[131]

The IWG broadly responded to the comments it received on the 2013 TSD in July 2015.[132] In that response, the IWG reiterated that the "purpose of [the IWG's] process was to ensure that agencies were using the best available information and to promote consistency in the way agencies quantify the benefits of reducing CO_2 emissions, or costs from increasing emissions, in regulatory impact analyses."[133]

The IWG updated its estimates of the SC-CO_2 again in August of 2016[134], and while API and others continued to have concerns with the transparency and rigor with which the IWG selected its model inputs, the TSD for the 2016 SC-CO_2 reflected some improvement to the characterization of uncertainty that was consistent with the NASEM Phase

[123] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.
[124] Technical Support Document: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (February 2020) ("2010 TSD) at 3.
[125] *Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin*., 538 F.3d 1172, 1200 (9th Cir. 2008).
[126] 2021 TSD at 10.
[127] 2010 TSD at 4.
[128] 2010 TSD at 5.
[129] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.
[130] OMB's first-ever solicitation of public comment on the SC-CO_2 estimates was likely in response to a September 4, 2013 multi-association Petition for Correction filed under the Information Quality Act ("IQA") and numerous demands from Congress and other stakeholders for increasing the transparency of the SC-CO_2 estimation process.
[131] *See* multi-association comments filed February 26, 2014 (OMB-2013-0007-0140). OMB's July 2015 Response to Comments did not provide the key information sought by API and others, and resisted recommendations that the IWG select these parameters through a transparent process subject to peer review. (*See* July 2015 Response to Comments: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866.) To its credit, however, OMB requested feedback from the NASEM on the IWG's process for updating the estimates of the SC-CO_2. (*See* NASEM 2017 at 1).
[132] Response to Comments: Social Cost of Carbon for Regulatory Impact Analysis Under Executive Order 12866 (July 2015) ("2015 RTC").
[133] 2015 RTC at 3.
[134] 2016a TSD.

1 Report,[135] as well as API's prior comments. Notably, in an addendum to the 2016 TSD, the IWG adapted its SC-CO_2 methodology to estimate social costs for methane and nitrous oxide for the first time.[136] While the 2016 TSD represented the first time the IWG provided estimates of non-CO_2 GHG emissions, the IWG continued to represent that the purpose of the estimates was to allow agencies to consistently "incorporate the social benefits of reducing . . . emissions into cost-benefit analyses of regulatory actions."[137]

Months later, President Trump disbanded the IWG and instead directed each agency to develop their own SC-GHG estimates using the same IAMs and the IWG's same overall methodology for estimating the SC-GHGs.[138] As the U.S. Department of Justice explained in its June 4, 2021 brief in opposition to several states' motion to preliminarily enjoin Section 5 of E.O. 13990, and the interim SC-GHG values published under E.O. 13990:

> Although the Trump Administration's policy approach to climate issues differed in many ways from that of the preceding administration, it continued to use standardized estimates of the social costs of greenhouse gases. Pursuant to E.O. 13783, EPA developed interim SC-CO_2 estimates by making two (*and only two*) changes to the Working Group's 2016 estimates: First, it began reporting estimates that attempted to capture only the domestic impacts of climate change, and second, it applied 3% and 7% discount rates. . . . Accordingly, although the Working Group had been disbanded, and although the estimates of the social costs of greenhouse gas estimates were now lower (because of higher discount rates and an exclusive focus on U.S.-domestic damages), agencies continued to estimate the social costs of greenhouse gases in their cost-benefit analyses, as ordered by the President, just as they had done in prior administrations.[139]

While these two changes[140] were seemingly modest, their impact on the SC-GHG estimates, was anything but small. When the Obama Administration conducted its RIA for the Clean Power Plan ("CPP") in 2015, it estimated social costs of \$12, \$40, \$60, and \$120 per short ton of CO_2 emissions for the 5%, 3%, 2.5%, and 95th percentile of the 3% discount rates for the year 2020 in 2011 dollars.[141] When the Trump Administration conducted its RIA for the review of the CPP in 2017, it estimated the SC-CO_2 to be \$6 per metric ton in 2020 (also in 2011 dollars) at the 3% discount rate, and \$1 at the 7% rate.[142]

> Thus, in the span of just two years, the same government agency, utilizing the 'best available science' put forth estimates for the same metric that had changed by so many orders of magnitude

[135] National Academies of Sciences, Engineering, and Medicine 2016. *Valuing Climate Damages. Assessment of Approaches to Updating the Social Cost of Carbon: Phase 1 Report on Near-Term Update*:. Washington, DC: The National Academies Press ("NASEM 2016").

[136] Addendum to Technical Support Document on Social Cost of Carbon for Regulatory Impact Analysis under Executive Order 12866: Application of the Methodology to Estimate the Social cost of Methane and the Social Cost of Nitrous Oxide ("2016b TSD"). OMB did not request or receive the NASEM's feedback on the new estimates of the social costs of methane and nitrous oxide, nor were they subject to notice and comment, or peer reviewed. Rather, they were premised entirely on a U.S. Environmental Protection Agency ("EPA") employee's 2015 paper, which at that point had not been reviewed or published. (*See* Martin, A.L., Kopits, E.A., Griffiths, C.W., Newbold, S.C., and A Wolverton. 2015. Incremental CH_4 and N_2O Mitigation Benefits Consistent with the U.S. Government's SC-CO_2 Estimates. *Climate Policy* 15(2): 272-298).

[137] 2016 TSD at 3.

[138] *See* Executive Order 13783 (March 28, 2017) ("E.O. 13783").[138]

[139] *Missouri v. Biden*, 4:41-cv-00287 (E.D. MO 2021) (Page 11 of Defendants' June 4, 2021 Combined Memorandum of Law in Support of Motion to Dismiss and in Opposition to Plaintiffs' Motion for a Preliminary Injunction) (emphasis added).

[140] These changes flowed from E.O. 13783 ("when monetizing the value of changes in greenhouse gas emissions resulting from regulations, including with respect to the consideration of domestic versus international impacts and the consideration of appropriate agencies shall ensure, to the extent permitted by law, that any such estimates are consistent with the guidance contained in OMB Circular A-4.")

[141] U.S. EPA, EPA-452/R-15-03 Regulatory Impact Analysis for the Clean Power Plan (2015) at 4-2. (The four SC-CO2 estimates differ based on use of discount rates of 5%, 3%, 2.5%, and the ninety-fifth percentile distribution at the 3% discount rate. (See 4-6, 4-7).

[142] U.S. EPA, Regulatory Impact Analysis for the Review of the Clean Power Plan: Proposal (2017) at 44. The conversion factor for metric ton to short ton is approximately 0.91, such that these estimates were actually about 9% lower when compared to the Obama-era estimates (2017 CPP RIA at 44).

as to be farcical. This was the case even though the Trump and Obama analyses utilized the same underlying models.[143]

Just a few years later, the IWG has republished the prior 2016 SC-GHG values as the new Interim SC-GHG estimates, and as instructed by E.O. 13990, these estimates "tak[e] global damages into account" and utilize discount rates that the IWG believes "reflect the interests of future generations in avoiding threats posed by climate change."[144] As a result, the Trump Administration's estimated SC-CO_2 values of $1 and $6 per metric ton in 2020 (in 2011 dollars)[145] increased to $14, $51, $76, and $152 per metric ton of CO_2 emissions for the 5%, 3%, 2.5%, and 95th percentile of the 3% discount rates for the year 2020 (in 2020 dollars).[146]

This whipsawing of SC-GHG estimates is not based on any objective errors or omissions. Indeed, the IWG and Trump Administration can both point to academic scholarship and regulatory guidance in support of their selections of discount rates and geographic scales. Rather, these divergent estimates demonstrate the extent to which any given estimate of the SC-GHG differs based on one or two subjective judgements. The output of the models is dependent on subjective framing decisions that "reflect ideology as much as they reflect the actual, long-term externality cost of climate change."[147] And because many of the key analytical framing decisions that truly drove model output are subjective and not purely scientific determinations, robust and transparent stakeholder and public engagement is essential.

As API urged in its comments on the 2021 TSD and reiterates here, the sensitivity of SC-GHG modeling output to one or a few subjective inputs raises serious questions of the SC-GHG estimates' reliability and utility in rulemaking and policy analyses. It also illustrates the profound importance of adopting analytical framing decisions through a structured and predictable process that is open, transparent, and data-driven. While EPA may have valid reasons for unilaterally developing its own SC-GHG estimates, API is concerned that this unexplained deviation from the SC-GHG estimation and updating process that was historically consigned and recently re-entrusted to the IWG reflects another *ad hoc* estimation approach that lacks the necessary structure, consistency, and transparency.

Moreover, given that EPA's SC-GHG Report contains the most recent estimate of the SC-GHG provided by the federal government, API is concerned that other federal agencies may opt to rely on the estimates in the EPA's SC-GHG Report rather than the estimates in the IWG's 2021 Interim TSD. While this concern is somewhat mitigated by E.O. 13990's requirement that agencies use the IWG's values, the absence of any clear statement from EPA as to what the SC-GHG Report is or how its estimates are to be used perpetuates a serious concern that EPA's values may be misapplied in a variety of different regulatory and administrative contexts.

III. DETAILED COMMENTS

API is concerned about the procedures EPA employed when developing the SC-GHG Report and the revised estimates contained therein. We also have substantive technical questions and concerns about the methodology EPA employed in generating the revised SC-GHG estimates and the manner in which the Agency presented its

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143 Taylor, A. (2018). Why the social cost of carbon is red herring. Tulane Environmental Law Journal, 31(2), 345-372 at 347.
144 E.O. 13990 at Sec. 5(a) and 5(b)(iii).
145 Using discount rates of 7% and 3%.
146 Interim TSD at Table ES-1 (using discount rates of 5%, 3%, 2.5%, and the 95th percentile of the 3% discount rate)
147 Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 370. [T]hose who would consider inclusion of IAM-generated estimates, particularly high-dollar ones, of the SCC to be an unmitigated success should nonetheless pay heed to the crow on the shoulder: a high degree of arbitrariness is currently baked into these estimates and it is quite difficult to know the degree to which they may be relied upon for accuracy or manipulated by agencies across different administrations.

estimates in the SC-GHG Report. Finally, API believes that EPA should more fully and explicitly explain why the inherent limits of the SC-GHG estimates render them unsuitable for agency rulemaking and decisions that require the SC-GHG to be expressed as a single value or within a reasonably narrow range of uncertainty. The subsections that follow discuss each of these three broad areas of concern in detail.

a. Procedural Concerns

As President Biden noted in Executive Order 13990 ("E.O. 13990") on his first day in office, "[a]n accurate social cost is essential for agencies to accurately determine the social benefits of reducing greenhouse gas emissions when conducting cost-benefit analyses . . ."[148] To that end, E.O. 13990 further instructed that, in undertaking actions such as developing SC-GHG estimates, "the Federal Government must be guided by the best science and be protected by processes that ensure the integrity of Federal decision-making.[149] Consistent with that mandate, President Biden also issued a Presidential Memorandum to all heads of executive departments and agencies reaffirming the Biden Administration's commitment to the principles outlined in President Clinton's Executive Order 12866 ("E.O. 12866")[150], which established the basic foundation for executive branch review of regulations, and President Obama's Executive Order 13563 ("E.O. 13563"),[151] which "took important steps toward modernizing the regulatory review process."[152]

Thus, through the Regulatory Review Memorandum, President Biden reaffirmed his administration's commitment to "allow for public participation and an open exchange of ideas;"[153] using "best available techniques to quantify anticipated present and future benefits and costs as accurately as possible;"[154] and ensuring "the objectivity of any scientific and technological information and processes used to support . . . regulatory actions."[155]

One week later, President Biden reiterated to his executive departments and agency heads that "[i]t is the policy of my Administration to make evidence-based decisions guided by the best available science and data."[156] According to the President Biden's Scientific Integrity Memorandum, "[w]hen scientific or technological information is considered in policy decisions, it should be subjected to well-established scientific processes, including peer review where feasible and appropriate. . ."[157]

API supports the principles President Biden outlined in these Executive Orders and presidential memoranda, and believes that certain aspects of EPA's development of SC-GHG estimates, such as taking public comment and committing to peer review, are broadly consistent with these principles. In other respects, however, EPA's development of the SC-GHG Report thus far appears to be the product of an insufficiently structured and transparent process.

Indeed, EPA's SC-GHG Report represents an unexplained departure from the more structured, transparent, and collaborative interagency process that the Biden Administration promised when it encouraged stakeholders

[148] E.O. 13990 at Sec. 5.
[149] E.O. 13990 at Sec. 1.
[150] Signed Sept. 30, 1993.
[151] Signed Jan. 18, 2011.
[152] Memorandum for the Heads of Executive Departments and Agencies regarding "Modernizing Regulatory Review" (Jan. 20, 2021) ("Regulatory Review Memorandum").
[153] E.O. 13563 at Sec. 1(a).
[154] E.O. 13563 at Sec. 1(c).
[155] E.O. 13563 at Sec. 5.
[156] "Memorandum on Restoring Trust in Government Through Scientific Integrity and Evidence-Based Policymaking" Memorandum From President Biden to the Heads of Executive Departments and Agencies (Jan. 27, 2021) ("Scientific Integrity Memorandum"). *See also* Executive Order 14007, which establishes the President's Council of Advisors on Science and Technology. (Jan. 27, 2021) ("E.O. 14007).
[157] Scientific Integrity Memorandum preamble.

interested in the SC-GHG development process to engage with the IWG. EPA's SC-GHG Report reflects no consideration of the comments API and others submitted to the IWG, and the limited data and time that EPA has provided at this stage does not appear consistent with a strong Agency interest in soliciting critical analysis. Furthermore, EPA's curious solicitation of comments on the SC-GHG Report within an NSPS rulemaking, which does not utilize the SC-GHG Report, does not particularly reflect an interest in transparency and collaboration. In fact, EPA's equivocal and fluctuating descriptions of the SC-GHG Report make it impossible for the public to even understand why EPA drafted the SC-GHG Report in the first place, or how the Agency intends to use it.

1. Lack of Clarity Regarding What the SC-GHG Report is and how it will be used

In both the preamble to the Proposed NSPS Revisions and the RIA in EPA's docket for the Proposed RIA Revisions ("Docketed RIA"), EPA concludes that the IWG's "interim SC-GHG estimates represent the most appropriate estimate of the SC-GHG until revised estimates have been developed reflecting the latest, peer-reviewed science."[158] Therefore, the Agency "estimated the climate benefits of methane emission reductions expected from this proposed rule using the social cost of methane (SC-CH_4) estimates presented in the [IWG's 2021 TSD]."[159]

Having disclaimed that the RIA estimated the climate benefits of the proposal's anticipated methane reductions using only the interim SC-GHG estimates from the IWG's 2021 TSD, EPA's preamble to the Proposed NSPS Revisions then describes the SC-GHG Report as "a sensitivity analysis of the monetized climate benefits using a set of SC-CH_4 estimates that incorporates recent research addressing recommendations of the National Academies of Sciences, Engineering, and Medicine."[160] According to EPA's preamble, the RIA presents the results of the SC-GHG Report's screening analysis in "Appendix B of the RIA."[161] However, the Docketed RIA does not include the sensitivity analysis EPA described in the preamble, nor does it contain any reference to, or even mention of, the SC-GHG Report.

Earlier versions of the RIA that were exchanged between and edited by EPA, OMB, and other agencies reflect that the RIA previously contained a substantial discussion of the SC-GHG Report and also included EPA's new estimates from the SC-GHG Report in a sensitivity analysis in a then-designated Appendix B.[162] These aspects of the draft RIA were deleted in their entirety without explanation shortly before publication of the Proposed NSPS Revisions. However, and particularly problematic from the perspective of transparency in public engagement as well as EPA's docket and rulemaking requirements under CAA Section 307, the version of the RIA that EPA posted on its website for public comment on November 11, 2022 contains the subsequently deleted discussion of the SC-GHG Report and Appendix B sensitivity analysis.[163] Thus, EPA is presently soliciting comments on two strikingly different versions of the Draft RIA. Indeed, while it is beyond the scope of this appendix's specific focus on EPA's SC-GHG Report, the Agency's publication of two divergent Draft RIAs raises significant questions about the sufficiency of the notice-and-comment opportunity on the required E.O. 12866 analysis as well as the Proposed NSPS Revisions.

While EPA's last minute revisions to the RIA remain unexplained, what is clear from the Docketed RIA is that EPA's SC-GHG Report is not a sensitivity analysis, and that the report's revised SC-GHG estimates are not amenable for use in sensitivity analyses. EPA's "Sensitivity and Uncertainty Analyses: Training Module" describes a "sensitivity analysis" as "a method to determine which variables, parameters, or other inputs have the most influence on the

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[158] 87 Fed. Reg. at 74,843; Docketed RIA (EPA-HQ-OAR-2021-0317-0173) at 3-6.
[159] 87 Fed. Reg. at 74,713; *See also* 87 Fed. Reg. at 74,843; *See also* the RIA in EPA's docket for the Proposed NSPS Revisions at 3-6.
[160] 87 Fed. Reg. at 74,843.
[161] 87 Fed. Reg. at 74,714, Table 5, note b; *See also* 87 Fed. Reg. at 74,843.
[162] *See* Draft RIA revisions between September and November 2021 at EPA-HQ-OAR-2021-0317-1540,1541, 1542, 1543, 1544, 1545, 1546, 1548, 1573, 1574, 1575, and 1576.
[163] *See* https://www.epa.gov/environmental-economics/scghg.

model output."[164] Consistent with this description, EPA's Training Module explains that "[t]here can be two purposes for conducting a sensitivity analysis [1] comput[ing] the effect of changes in model inputs on the outputs; [2] to study how uncertainty in a model output can be systematically apportioned to different sources of uncertainty in the model input."[165]

EPA's SC-GHG Report and the SC-GHG estimates contained therein are in no way suited to these purposes. The estimates in EPA's SC-GHG Report were derived in a manner wholly different from the IWG's SC-GHG estimates. For each of the four modules of the SC-GHG estimation process - socioeconomics and emissions, climate, damages, and discounting – EPA's SC-GHG Report uses different models, methodologies, analytical framing decisions, and data than the IWG utilized. As detailed in the Executive Summary to the SC-GHG Report:

> The socioeconomic and emissions module relies on a new set of probabilistic projections for population, income, and GHG emissions developed under the Resources for the Future Social Cost of Carbon Initiative . . . The climate module relies on the Finite Amplitude Impulse Response (FaIR) model… The socioeconomic projections and outputs of the climate module are used as inputs to the damage module to estimate monetized future damages from temperature changes. Based on a review of available studies and approaches to damage function estimation, the report uses three separate damage functions to form the damage module. They are: 1. a subnational-scale, sectoral damage function… 2. a country-scale, sectoral damage function… and 3. a meta-analysis-based damage function… The discounting module . . . us[es] a set of dynamic discount rates that have been calibrated following the Newell et al. (2022) approach, as applied in Rennert et al. (2022a, 2022b). … Uncertainty in the starting rate is addressed by using three near-term target rates (1.5, 2.0, and 2.5 percent) based on multiple lines of evidence on observed market interest rates. … Finally, the value of aversion to risk associated with damages from GHG emissions is explicitly incorporated into the modeling framework following the economic literature. The estimation process generates nine separate distributions of estimates – the product of using three damage modules and three near-term target discount rates – of the social cost of each gas in each emissions year. To produce a range of estimates that reflects the uncertainty in the estimation exercise while providing a manageable number of estimates for policy analysis, in this report the multiple lines of evidence on damage modules are combined by averaging the results across the three damage module specifications.[166]

Every aspect of the above-described estimation process differs from the process employed by the IWG. And, because every aspect of EPA's SC-GHG estimation process differed from the IWG's process, it does not allow EPA "to determine which variables, parameters, or other inputs" in the IWG's estimation process "have the most influence on the model output." Examining two wholly different estimation processes does not provide any basis to discern how any of the IWG's inputs may impact the IWG's model output or apportion uncertainty to the IWG's various inputs.

"Sensitivity analyses" require the isolation and examination of one or a few model inputs while all other model parameters remain constant. For instance, in the 2021 TSD, the IWG advised that "agencies may consider

[164] *See* https://archive.epa.gov/epa/measurements-modeling/sensitivity-and-uncertainty-analyses-training-module.html#:~:text=Sensitivity%20analysis%20(SA)%20is%20the,)%20(EPA%2C%202003).
[165] *See* https://archive.epa.gov/epa/measurements-modeling/sensitivity-and-uncertainty-analyses-training-module.html#:~:text=Sensitivity%20analysis%20(SA)%20is%20the,)%20(EPA%2C%202003).
[166] SC-GHG Report at 1-2.

conducting additional sensitivity analysis using discount rates below 2.5 percent."[167] Consistent with EPA's Training Module and standard practices for conducting sensitivity analyses, the IWG instructed that agencies' sensitivity analyses should isolate a single input (the discount rate) in order to assess the impact of changes from that single input on the model output.

The estimates in EPA's SC-GHG Report are simply new estimates based on new methods and data, and they therefore plainly have no value in any scientifically relevant sensitivity analysis. Indeed, what EPA deemed a "Screening Analysis" in the since-deleted sections of the Docketed RIA was not a screening analysis at all, at least as defined by EPA's Training Module. EPA merely compared the values from the IWG's 2021 TSD to EPA's SC-GHG Report and found that the benefits estimated in EPA's SC-GHG Report were higher than the IWG's 2021 interim estimates. This is truly the full extent of EPA's use of the SC-GHG Report for a "sensitivity analysis," which perhaps explains the Agency's decision to strike those references from the Docketed RIA.

Recognizing that neither EPA's SC-GHG Report nor the estimates contained therein constitute, or can credibly be used in sensitivity analyses, one is compelled to recognize the SC-GHG Report's estimates for what they are – SC-GHG values that are wholly separate and distinct from the 2021 IWG interim SC-GHG estimates that the Biden Administration directed all agencies to use. In fact, the SC-GHG Report itself never suggests its estimates are intended or even suitable for sensitivity analyses. The SC-GHG Report accurately describes them as "new estimates of the SC-GHG."[168]

Indeed, the SC-GHG Report's estimates are "new estimates of the SC-GHG," but given EPA's deletion of the supposed "sensitivity analysis" and assertion that the SC-GHG Report's estimates were not used in the RIA or the "statutory [best system of emissions reduction] determinations" in the Proposed NSPS Revisions,[169] commenters are left with no explanation why EPA developed the SC-GHG Report, how EPA intends to use the report's estimates, or why EPA included the SC-GHG Report in the docket for the Proposed NSPS Revisions. A truly transparent and collaborative process demands much more than this. EPA should provide a full and complete explanation for the development and intended use of the SC-GHG Report before subjecting it to peer review or public comment. Absent any explanation of the SC-GHG Report's intended use, reviewers have little basis to opine on its suitability.

2. Inconsistency with the Biden Administration's Stated Approach to the SC-GHG

From the earliest days of his Administration and consistently thereafter, President Biden and other Administration officials publicly committed to developing and updating government-wide SC-GHG estimates through the IWG by prescribing a detailed and incremental process. Based on the Administration's representations, API and other stakeholders devoted significant time and resources attempting to engage the IWG, but the rigorous and transparent IWG process that the Biden Administration promised has not yet materialized in any meaningful way. Now, more than two years after the IWG released its first and only publication of the several it had been charged with developing, EPA appears to be charting its own course by developing its own agency-specific SC-GHG estimates in the SC-GHG Report.

As discussed in more detail below, EPA's independent development of SC-GHG estimates is incompatible with and, in fact, undermines the unified approach promised by the Biden Administration in E.O 13990. We also describe

[167] 2021 TSD at 4; *See also* 2021 TSD at 21 ("the IWG finds it appropriate as an interim recommendation that agencies may consider conducting additional sensitivity analysis using discount rates below 2.5%.").
[168] SC-GHG Report at 84.
[169] 87 Fed. Reg. at 74,843.

why EPA's unilateral SC-GHG estimates and any subsequent proliferation of agency-specific SC-GHG estimates contravene the Administration's stated interest in assessing the benefits and costs of proposed regulations consistently and cohesively across all federal agencies.

i. President Biden's Promised Approach for the Development and Agency use of SC-GHG Estimates

After the Trump Administration disbanded the IWG, President Biden on his first day in office issued E.O. 13990, which reestablished the IWG as the federal entity charged with developing and publishing the SC-GHG estimates that are to be used by all federal agencies.[170] The IWG's mission is fivefold:

> (A) publish an interim [SC-GHG] within 30 days of the date of this order, which agencies shall use when monetizing the value of changes in greenhouse gas emissions resulting from regulations and other relevant agency actions until final values are published;
>
> (B) publish a final [SC-GHG] by no later than January 2022;
>
> (C) provide recommendations to the President, by no later than September 1, 2021, regarding areas of decision-making, budgeting, and procurement by the Federal Government where the [SC-GHG] should be applied;
>
> (D) provide recommendations, by no later than June 1, 2022, regarding process for reviewing, and, as appropriate, updating, the [SC-GHG] to ensure that these costs are based on the best available economics and science; and
>
> (E) provide recommendations, to be published with the final [SC-GHG] under subparagraph (A) if feasible, and in any event by no later than June 1, 2022, to revise methodologies for calculating the [SC-GHG], to the extent that current methodologies do not adequately take account of climate risk, environmental justice, and intergenerational equity.[171]

Insofar as API is aware, the IWG has only completed the first of the five tasks prescribed by E.O. 13990.[172] Regarding these interim estimates, the E.O. mandates that "agencies ***shall*** use" them in promulgating their own "regulations and other relevant agency actions until final values are published."[173] Thus, although it is unclear why EPA developed the SC-GHG Report and how the Agency intends its SC-GHG estimates to be used, it bears mentioning that agencies deviating from these interim estimates do so in contravention with E.O. 13990.

The requirements of E.O. 13990 are also memorialized in the 2021 Interim TSD, which describes President Biden's directive that the reconstituted IWG "ensure that SC-GHG estimates used by the U.S. Government (USG) reflect the best available science and the recommendations of the National Academies (2017)…"[174] Consistent with the Executive Order, the IWG plainly recognized that the SC-GHG estimates it developed were to be used throughout the "U.S. Government," unless expressly precluded by statute.[175]

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[170] E.O. 13990 at Sec. 5.
[171] E.O. 13990 at Sec. 5(b)(ii).
[172] 2021 TSD.
[173] E.O. 13990 at Sec. 5(b)(ii)(a) (emphasis added).
[174] 2021 TSD at 3.
[175] Social Cost of Greenhouse Gas Emissions: Frequently Asked Questions (FAQs), ("OIRA Guidance") at 2, June 3, 2021. Available at https://www.whitehouse.gov/wp-content/uploads/2021/06/Social-Cost-of-Greenhouse-Gas-Emissions.pdf.

The IWG's Interim TSD goes on to instruct that the Interim SC-GHG estimates "should be used by agencies until a comprehensive review and update is developed in line with the requirements in E.O. 13990."[176] The Interim TSD also "determined that it is appropriate for agencies to revert to the same set of four values drawn from the SC-GHG distributions based on three discount rates (2.5 percent, 3 percent, and 5 percent) as were used in regulatory analyses between 2010 and 2016 and subject to public comment."[177]

OMB, the entity responsible for coordinating the IWG efforts,[178] has likewise confirmed that President Biden's reconstitution of the IWG demonstrates that the President intended the IWG alone develop the SC-GHG estimates necessary "to ensur[e] that the estimates agencies consider . . . reflect the best available science and methodologies."[179] This directive is further confirmed in the June 2021 guidance document OIRA issued to agencies to assist in applying Section 5 of E.O. 13990.[180] The OIRA Guidance clarified that "[p]ursuant to E.O. 13990, when agencies prepare an assessment of the potential costs and benefits of regulatory action for purposes of compliance with E.O. 12866, they *must* use the 2021 interim estimates in monetizing increases or decreases in greenhouse gas emissions that result from regulations and other agency actions until updated values are released by the IWG."[181] Accordingly, E.O. 13990, the 2021 Interim TSD, OMB's solicitation of comments on the Interim TSD, and OIRA's guidance not only directed federal agencies to use the IWG's SC-GHG estimates, they apprised stakeholders interested in the federal government's SC-GHG estimates that the IWG was the sole entity with which to engage regarding the development of these important values.

In litigation surrounding E.O. 13990 and the 2021 Interim TSD, the U.S. Department of Justice ("DOJ") also describes the Biden Administration's stated approach to developing and using SC-GHG estimates, and opined on the degree to which E.O. 13990 compelled agencies to use the IWG's values:

> … the Executive Order requires agencies to use the Interim Estimates in some circumstances. *See* E.O. 13990 §§ 5(b)(ii)(A) (using the word "shall"); OIRA Guidance, at 1. But that directive is inoperative whenever the agency faces any conflicting statutory obligation . . .In other words, agencies will only ever rely on the Interim Estimates when they have discretion to do so…[182]

As DOJ stated elsewhere even more succinctly, "if an agency undertakes [SC-GHG] monetization, it shall use the Interim Estimates rather than another set of figures."[183]

ii. EPA's SC-GHG Report Contravenes the Approach President Biden Promised Stakeholders

Although it is not yet clear how EPA intends to use the estimates in its SC-GHG Report, the Agency's development and publication of these values appears to conflict with President Biden's explicit directive that the IWG develop the federal government's SC-GHG estimates and that federal agencies use those estimates. The Administration assigned this centralized role to the IWG "to ensur[e] that the estimates agencies consider . . . reflect the best available science and methodologies."[184] Even though EPA is a key member of the IWG and EPA's staff certainly

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[176] 2021 TSD at 4.
[177] 2021 TSD at 4.
[178] *See* E.O. 13990 at Sec. 5; *See also* 86 Fed. Reg. at 24,669.
[179] 86 Fed. Reg. at 24,669.
[180] *See* OIRA Guidance.
[181] OIRA Guidance at 1.
[182] Defendants' Combined Memorandum of Law in Support of Motion to Dismiss and in Opposition to Plaintiffs' Motion for a Preliminary Injunction, Page 23, *Missouri et al., v. Biden, et al.*, Case No. 4:21-cv-00287-AGF (E.D. Mo. 2021).
[183] Brief for Appellees, Page 40, *Missouri et al., v. Biden, et al.*, Case No. 4:21-cv-00287-AGF (E.D. Mo. 2021).
[184] 86 Fed. Reg. at 24,669.

have a high level of expertise in climate science and economic analysis, E.O. 13990's reestablishment of the IWG seems to indicate that the Biden Administration believed that development of the highly important SC-GHG estimates called for a breadth of expertise and diversity of opinions unlikely to be found within a single agency.

While API has often disagreed with the IWG's lack of transparency and with various modeling decisions and methodologies that the IWG has employed in developing SC-GHG estimates, we believe that the multi-agency composition of the IWG provides at least an opportunity to develop future SC-GHG estimates using a greater diversity of viewpoints and expertise. Thus, when the Biden Administration once again consigned the federal government's SC-GHG estimation process to the IWG, API once again devoted significant time and resources developing comments reflecting our own viewpoints and considerable expertise. Unfortunately, the IWG's unexplained inaction on the tasks it was assigned in E.O. 13990 along with EPA's unilateral development of SC-GHG estimates in contravention with E.O. 13990 seem to indicate that API's efforts to engage the IWG may have been in vain and that the process laid out in E.O. 13990 has been inexplicably abandoned.

API and others with a deep interest in, and credible expertise relevant to, the development of SC-GHG estimates are effectively precluded from meaningfully engaging with the federal government on these estimates if the Administration changes without explanation the entities, planned actions, and procedures for developing SC-GHG estimates.

The other reason the Administration re-established the IWG and tasked it with developing the SC-GHG estimates was "to promote consistency in the way agencies quantify the benefits of reducing CO_2 emissions in regulatory impact analyses."[185] This accords with OMB Circular A-4, which emphasizes that "[i]n undertaking [benefit-cost analysis and cost-effectiveness analysis], it is important to keep in mind the larger objective of analytical consistency in estimating benefits and costs *across regulations and agencies*, subject to statutory limitations."[186]

While we recognize that the Administration has announced its intent to revise Circular A-4,[187] the mere prospect of these revisions provides no basis for contravening the guidelines and instructions currently provided by Circular A-4. Unless and until Circular A-4 is revised or replaced, it should continue to guide EPA and other agencies to develop clear, transparently supported, objective, and consistent RIAs. Indeed, far from justifying any departures from Circular A-4's guidelines, the Administration's announcement that Circular A-4 will be revised further illustrates that EPA's unilateral development of SC-GHG estimates is inconsistent with the overall RIA and SC-GHG development framework that the Biden Administration publicly announced.

Finally, the need for a single consistent process for developing the SC-GHG estimates used in RIAs is further reflected in a 2020 Government Accountability Office ("GAO") Report on the SC-GHG and specifically the manner in which the federal government should address the recommendations of the National Academies."[188] Recognizing that the National Academies' recommended procedural and technical improvements could not be feasibly implemented by a multitude of different agencies, the GAO urged OMB to "identify a federal entity or entities to be responsible for addressing the National Academies' recommendations…"[189] GAO considered the recommendation "implemented" when E.O. 13990 reinstated the IWG.[190]

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[185] 2021 TSD at 10.
[186] OMB Circular A-4, Pages 9-10 (emphasis added).
[187] Joseph Biden Jr. 2021. Memorandum for the Heads of Executive Departments and Agencies; Modernizing Regulatory Review. The White House.
[188] GAO-20-254, Report to Congressional Requesters, SOCIAL COST OF CARBON: Identifying a Federal Entity to Address the National Academies' Recommendations Could Strengthen Regulatory Analysis ("GAO-20-254").
[189] GAO-20-254.
[190] GAO-20-254 Recommendation Status, https://www.gao.gov/products/gao-20-254#summary_recommend.

Thus, EPA's unexplained deviation from the SC-GHG development approach laid out in E.O. 13990 not only upends the process to which API and other have devoted time and resources, it undermines the federal government's longstanding objective of making RIAs more consistent across agencies and detracts from what the GAO and this Administration identified as necessary to improve the SC-GHG estimation process consistent with the National Academies' recommendations.

3. Failure to Respond to Comments

As a further consequence of the Agency's decision to unilaterally develop its own SC-GHG estimates, EPA's SC-GHG Report does not appear to be based on any meaningful consideration of the many significant and detailed comments submitted to the IWG, including most recently, the many comments in response to the 2021 Interim TSD. Based on the Biden Administration's representation that the IWG alone would develop the SC-GHG estimates that would be used by the many agencies of the federal government, "[t]he Office of Management and Budget (OMB), on behalf of the cochairs of the Interagency Working Group on the Social Cost of Greenhouse Gases, including the Council of Economic Advisors (CEA) and the Office of Science and Technology Policy (OSTP)," requested "public comment on the interim TSD as well as on how best to incorporate the latest peer-reviewed science and economics literature in order to develop an updated set of SC–GHG estimates."[191]

Notwithstanding that the IWG purported to solicit public comments "in order to facilitate early and robust interaction with the public on this key aspect of this Administration's climate policy,"[192] neither the IWG nor EPA, which is a key member of the IWG, ever responded to or meaningfully considered the public comments submitted by API and many others in 2021. This does not represent a valid and transparent effort to engage the public and solicit feedback to improve agency decision-making.

"For an agency's decisionmaking to be rational, it must respond to significant points raised during the public comment period."[193] EPA is not relieved of this obligation simply because the comments were solicited by OMB on behalf of the IWG. As a key member of the IWG, EPA "reviewed the comments submitted to the IWG,"[194] and therefore had an obligation to "engage the arguments raised before it."[195]

The issues on which the IWG solicited comment, including advances in science and economics, approaches for implementing the National Academies' recommendations, approaches for intergenerational equity, and the use of discount rates,[196] are directly relevant to the EPA's SC-GHG Report. So too are the significant comments and data submitted by API and others in response to the IWG's solicitation.

In particular, API submitted detailed and constructive questions and comments on issues regarding the selection of discount rates, the ability to reasonably forecast impacts on expansive time horizons, and the importance of providing domestic SC-GHG values alongside global values. The IWG never responded to these comments and questions, and given the existence of these same concerns in EPA's SC-GHG Report, EPA plainly ignored API's comments as well.

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[191] 87 Fed. Reg. 24,669 (May 7, 2021).
[192] 87 Fed. Reg. at 24,670.
[193] *Allied Local & Reg'l Mfrs. Caucus v. EPA,* 215 F.3d 61, 68 (D.C. Cir. 2000).
[194] SC-GHG Report at 8.
[195] *Del. Dep't of Nat. Res. & Envtl. Control v. EPA*, 785 F.3d 1, 11 (D.C. Cir. 2015); *see Nat'l Shooting Sports Found., Inc. v. Jones*, 716 F.3d 200, 214 (D.C. Cir. 2013).
[196] 87 Fed. Reg. at 24,670.

It is not enough for EPA to suggest that it "has reviewed the comments submitted to the IWG in developing [the SC-GHG Report]."[197] EPA must respond in a reasoned manner to the comments received, [] explain how the agency resolved any significant problems raised by the comments, and [] show how that resolution led the agency to [its conclusion]."[198] "Consideration of comments as a matter of grace is not enough.' It must be made with a mind open to persuasion."[199]

It is also insufficient that EPA is now accepting comment on the SC-GHG Report. To begin, EPA's acceptance of comments on entirely new SC-GHG estimates in a wholly distinct SC-GHG Report in no way mitigates the absence of any record that EPA meaningfully engaged with or responded to any of the comments already submitted to the IWG.

Further, while it remains unclear what the SC-GHG Report is or how EPA intends to use it, nowhere does EPA represent that the report is in draft form or that the Agency will revise the SC-GHG Report based on comments and data received. On the contrary, EPA states that the "report presents new estimates of the SC-GHG" that EPA may rely upon "while [the IWG] process continues."[200] Therefore, if EPA intends to use and rely on the values in the SC-GHG Report as they are currently estimated, the Agency's solicitation of comments at this point does not truly "allow for public participation and an open exchange of ideas."[201] Nor is such an approach consistent with the National Academies' recommendation that draft revisions to the SC-GHG methods and estimates should be subject to public notice and comment, allowing input and review from a broader set of stakeholders, the scientific community, and the public.[202]

4. <u>EPA has not Provided Interested Parties the Time or Information Necessary to Solicit Detailed and Constructive Feedback</u>

In order for its public comment process to be reasonable and therefore lawful, EPA must provide commenters access to the data, studies, and other records on which the Agency relied as well as reasonably adequate time to review the data and draft comments analyzing EPA's conclusions and findings based on those records. EPA's present solicitation of comments on the SC-GHG Report does not satisfy either of these requirements.

The U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") makes clear that when an agency relies on data that is critical to its decision-making process, that data must be disclosed in order to provide the public an opportunity to meaningfully comment on the agency's rulemaking rationale.[203] Indeed, the D.C. Circuit has consistently maintained that "[i]n order to allow for useful criticism it is especially important for the agency to identify and make available *technical studies and data* that it has employed in reaching the decisions to propose particular rules."[204]

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[197] SC-GHG Report at 8.
[198] *Indep. U.S. Tanker Owners Comm v. Lewis*, 690 F.2d 908, 919 (D.C. Cir. 1982).
[199] *Advocates for Hwy & Auto Safety v. Fed. Hwy. Admin*., 28 F.3d 1288, 1292 (D.C. Cir. 1994) (citing *McLouth Steel Products Corp. v. Thomas*, 838 F2d 1317, 1323 (D.C. Cir. 1988)).
[200] SC-GHG Report at 84.
[201] E.O. 13563 at Sec. 1(a).
[202] National Academies of Sciences, Engineering, and Medicine 2017. *Valuing Climate Damages: Updating Estimation of the Social Cost of Carbon Dioxide*: Washington, DC: The National Academies Press ("NASEM 2017") at Pages 58-60.
[203] *See, e.g., Conn. Light & Power Co. v. Nuclear Regulatory Comm'n,* 673 F.2d 525, 530 (D.C. Cir. 1982); *Chamber of Commerce v. SEC,* 443 F.3d 890, 899 (D.C. Cir. 2006); *Am. Radio Relay League, Inc. v. FCC,* 524 F.3d 227, 236-37 (D.C. Cir. 2008).
[204] *Conn. Light & Power Co.,* 673 F.2d at 530 (emphasis added); *See also Am. Radio Relay League, Inc.,* 524 F.3d at 237 ("It would appear to be a fairly obvious proposition that studies upon which an agency relies in promulgating a rule must be made available during the rulemaking in order to afford interested persons meaningful notice and an opportunity for comment.").

Moreover, because of the "complex scientific issues involved in EPA rulemaking" Congress established more rigorous requirements under the CAA for making information available for public scrutiny.[205] Hence, the CAA mandates that "[a]ll data, information, and documents . . . on which the proposed rule relies *shall* be included in the docket on the date of publication of the proposed rule."[206] This critical requirement is particularly relevant here because EPA claims to have utilized, and is taking comment on, the SC-GHG Report as part of the Proposed NSPS Revisions, which is a rulemaking pursuant to the CAA.[207]

Therefore, if "documents of central importance upon which EPA intended to rely had been entered in the docket too late for any meaningful public comment prior to promulgation, then both the structure and spirit of section 307 would have been violated."[208] "The Congressional drafters, after all, intended to provide 'thorough and careful procedural safeguards . . . [to] insure an effective opportunity for public participation in the rulemaking process.'"[209]

Notwithstanding this requirement, EPA's docket omits several studies, records, and other materials that appear fundamental to the Agency's development of the SC-GHG Report. For instance, EPA claims to have based several aspects of the SC-GHG Report on "the public comments received on individual EPA proposed rulemakings and the IWG's February 2021 TSD,"[210] but only identifies two supportive comments of the 88 total comments submitted on the 2021 TSD.[211] EPA did not identify or provide any comments "it received on individual EPA proposed rulemakings." Therefore, the Agency's administrative record for the SC-GHG Report is either insufficiently comprehensive or EPA impermissibly "rel[ied] on some comments while ignoring comments advocating a different position."[212]

Similarly, the SC-GHG Report relies extensively on SC-GHG estimation and modeling approach developed by RFF,[213] but while EPA's administrative record includes the RFF paper itself, it does not include all the data and studies that RFF utilized in developing those projections and estimates that EPA incorporated into its SC-GHG Report. For instance, RFF augments their economic forecast and generates their emissions forecast based on expert opinion,[214][215] but EPA's administrative record does not appear to contain any details or documentation regarding the expert elicitation and forecasting that was a key part of RFF's modeling effort. Given the critical importance of these forecasts in modelling the SC-GHG and EPA's implicit adoption of the forecasts in the SC-GHG Report, EPA should provide the public with details regarding how and why these experts were selected. For example, EPA should submit for public comment in the docket for the Proposed NSPS Revisions RFF's documentation, which details RFF's survey methodologies, partial selection methodology, and results. EPA should also extend the time period for submission of public comments on EPA's SC-GHG Report. Additionally, EPA should foster transparency by clarifying how RFF selected their experts from RFF's nominee pool.

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[205] *E.g., Small Ref. Lead Phase-Down Task Force v. EPA,* 705 F. 2d 506, 518 (D.C. Cir. 1983).
[206] CAA § 307(d)(3) (emphasis added); *see Kennecott Corp. v. EPA,* 684 F. 2d 1007, 1018 (CAA § 307(d)(3) requires EPA to place in the docket "the factual data on which the proposed regulations are based").
[207] 87 Fed. Reg. at 74,713.
[208] *Sierra Club v. Costle*, 657 F.2d 298 at 398 (D.C. Cir.1981); *See also Kennecott Corp. v. EPA*, 684 F.2d 1007, 1019 (D.C.Cir. 1982) (EPA improperly placed economic forecast data in the record only one week before issuing its final regulations).
[209] *Sierra Club v. Costle*, 657 F.2d 298 at 398 (citing H.R.Rep.No.95-294, 95th Cong., 1st Sess. 188 at 319 (1977)).
[210] SC-GHG Report at 26, 37, 53, and 8.
[211] SC-GHG Report at 14 (FN26), and 15 (FN37).
[212] *National Women's Law Center v. Office of Management and Budget*, 358 F. Supp. 3d 66, 91 (D.D.C. 2019).
[213] Rennert, K., Prest, B.C., Pizer, W.A., Newell, R.G., Anthoff, D., Kingdon, C., Rennels, L., Cooke, R., Raftery, A.E., Ševčíková, H. and Errickson, F., 2022a. The social cost of carbon: Advances in long-term probabilistic projections of population, GDP, emissions, and discount rates. Brookings Papers on Economic Activity. Fall 2021, pp.223-305.
[214] Rennert et al.'s economic growth survey included the following participants: Daron Acemoglu, Erik Brynjolfsson, Jean Chateau, Melissa Dell, Robert Gordon, Mun Ho, Chad Jones, Pietro Peretto, Lant Pritchett, and Dominique van der Mensbrugghe.
[215] Rennert et al.'s future emissions survey included the following participants: Sally Benson, Geoff Blanford, Leon Clarke, Elmar Kriegler, Jennifer Faye Morris, Sergey Paltsev, Keywan Riahi, Susan Tierney, and Detlef van Vuuren.

More fundamentally, as discussed in Section III.a.1, EPA's administrative record does not even sufficiently apprise the public as to why EPA developed the SC-GHG Report or how the Agency intends to use it. However, even if EPA had timely provided all of the documents of central importance upon which it relied in drafting the SC-GHG Report, the public comment period EPA provided remains woefully insufficient. The SC-GHG Report provides a completely new set of SC-GHG estimates that were generated through a substantially revised modular approach using entirely different methodologies, models, studies, data, and analytical framing decisions than have been used by the IWG. And while EPA has not populated the administrative record with the full universe of the centrally important records on which it relied, there are hundreds of sources cited in the SC-GHG Report and the RFF Study that provided significant portions of the analysis used in the SC-GHG Report. As evidenced by the five years it took RFF to develop its SC-GHG estimates[216] and the fact that the IWG is more than a year overdue in developing the final SC-GHG estimates required by E.O. 13990, reviewing SC-GHG estimates and their underlying methodologies and data is incredibly labor-intensive and time-consuming.

As such, EPA's decision to provide the public only 69 days to review, develop, and submit comments on the SC-GHG Report is plainly unreasonable – particularly so, given that the comment period coincided with the holiday season. EPA's comment deadline for the SC-GHG Report is also unreasonable because it is the same comment period through which EPA is soliciting comments on the Proposed NSPS Revisions. The proposed revisions are complex rules that will apply to hundreds of thousands of facilities not previously subject to regulation under the CAA. Because of the wide variety of conditions faced by these facilities, and the novel nature of a first ever existing source rule, the current comment deadline is insufficient for even the Proposed NSPS Revisions alone.

In sum, EPA's current administrative record and comment deadline for the SC-GHG Report do not reasonably "allow for public participation and an open exchange of ideas."[217] API therefore respectfully requests that EPA supplement the administrative record with all of the centrally relevant information EPA utilized in developing the SC-GHG Report and provide a new and substantially longer comment period focused exclusively on the SC-GHG Report and the estimates contained therein.

b. Technical Issues with EPA's Methodology and Presentation of the SC-GHG Estimates

In addition to the procedural issues API described in the preceding subsection, our review of the SC-GHG Report raised several significant questions and concerns about EPA's data selection, framing decisions, and modeling assumptions. It is critical the SC-GHG Report completely and transparently explain the precise bases for each of its analytical framing decisions because the SC-GHG estimates that EPA developed using the process described in the SC-GHG Report are highly sensitive to even modest changes to one or a few model choices and judgements.

Moreover, given the enormous and continually growing body of data and academic literature relevant to estimating the SC-GHG, the process by which EPA selects the data and literature on which it relies must be rigorous, objective, and transparent. Thus, when describing the evidentiary bases for its SC-GHG estimates, the SC-GHG Report should not only identify the studies on which the Agency relied, it must reasonably explain and describe why EPA declined to utilize other credible academic literature and data.

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[216] https://www.resources.org/archives/the-social-cost-of-carbon-reaching-a-new-estimate/?_gl=1*becwm3*_ga*OTczMDg2OTQzLjE2NzQ3NTAyOTI.*_ga_HNHQWYFDLZ*MTY3NDg0OTI4Ny4yLjEuMTY3NDg0OTMyMi4wLjAuMA.

[217] E.O. 13563 at Sec. 1(a).

The bullets below briefly describe a number of the questions and concerns that API and its members raised after reviewing the SC-GHG Report. Given the constrained timeframe for review and comment, these questions and concerns should by no means be considered exhaustive or complete. Rather, we urge EPA to view these questions and concerns as emblematic of API's broader concern with the manner in which the SC-GHG Report describes and supports EPA's model choices and SC-GHG estimation process.

- **Damage functions** – Two of the damage functions used in EPA's new SC-GHG model estimate damages at a subnational and/or sectoral level. However, there is no discussion about why EPA excluded other damage functions, particularly those produced by structural economy-wide models.[218] EPA should identify all the possible damage function approaches that could be incorporated and discuss the relative merits and shortcomings of each so stakeholders can understand EPA's rationale for their selected approach.

  Furthermore, given the relative importance of mortality-related impacts in the two sectoral damage functions, EPA should place more attention on how response functions could be adjusted for differences in age distributions across regions. Carleton *et al.* 2020 demonstrated that the temperature-mortality response function differs substantially by age, with a particularly strong relationship observed in the 65+ population. While age is included as a covariate in some of the studies included in Cromar *et al.* 2022, it is not uniformly considered across the literature assessed there. For example, the studies that do adjust for age do not present full mortality results by age. Cromar *et al.* did not consider heterogeneity by age group in their models estimating future mortality associated with temperature changes even though some of the individual studies included in Cromar *et al.* accounted for age. The ideal temperature-mortality model and subsequent monetization would account for age group heterogeneity at all stages of the analysis and calculations.

  Additionally, the temperature-mortality function for a given location and population will likely change through implementation of adaptation measures, a critical consideration in the SC-GHG estimation for mortality. However, adaptation is not consistently incorporated into these studies; and those studies that include adaptation vary in the way it is incorporated. In Carleton *et al.* 2020, administrative level 2 gross domestic product ("GDP") per capita and mean annual temperature for each location incorporates adaptation such that the location-specific exposure-response curve accounts for heterogeneity in adaptation response. Cromar *et al.* did not incorporate adaptation measures at a global or region-specific level, despite stating the importance of incorporating adaptation. As these measures will vary by many factors, including the regional climate and socioeconomic status, it is important that any future projections of the temperature-mortality function account for potential adaptation to temperature change, and the ideal study would account for adaptation at the local level.

- **Discount rate** – There are several choices regarding the discount rate that deserve more consideration and discussion. First, EPA should more fully justify its claim that long-term structural breaks in the interest rate imply lower interest rates in the future.[219] EPA should also explain how near-term interest rates from the last thirty years can fully inform the choice of an appropriate discount rate for the SC-GHG given the projection horizon of 300 years. Other work[220] has considered interest rates over long-time horizons and disputed the notion of structural breaks which calls into question some of EPA's discount rate assumptions. Furthermore, EPA should

[218] Rose, S, D Diaz, T Carleton, L Drouet, C Guivarch, A Méjean, F Piontek, 2022. Estimating Global Economic Impacts from Climate Change. In Climate Change 2022: Climate Impacts, Adaptation, and Vulnerability. Contribution of Working Group II to the Sixth Assessment Report of the IPCC, Chapter 16.
[219] *See* SC-GHG Report at 59.
[220] Rogoff et al. 2022. Long-Run Trends in Long-Maturity Real Rates 1311-2021. National Bureau of Economic Research.

explain their rationale for using a single discount rate for all regions, given that certain parameters used to estimate it, such as the economic growth rate, clearly vary across regions.

Second, since EPA estimates Ramsey parameters using assumptions about these near-term interest rates, EPA should consider whether the implied Ramsey parameters are reasonable and consistent with other available information. For example, the pure rate of time preference (ρ) that EPA estimates under the 2 percent near-term discount rate (0.2 percent) is significantly lower than those found in the Drupp *et al.*[221] survey cited in the SC-GHG Report.[222] Moreover, the value of ρ under the 1.5 percent near-term discount rate is near-zero, even though as EPA notes "it has been argued that very small values of ρ can lead to an unreasonable rate of optimal savings (Arrow et al. 1995), particularly with η around 1 (Dasgupta 2008, Weitzman 2007)."[223] Such results further call into question the choice of near-term discount rates and the reasons why parameters such as the Ramey parameters were forced to accommodate particular near-term discount rates, rather than the opposite.

Third, related to the calibration, EPA should state and explain how it calculates the near-term real growth rate of consumption per capita (g_t) as this is one of the few elements within the Ramsey discount rate that is observable in the market. To recover EPA's Ramsey parameters, a near-term consumption per capita growth rate of around 1.45 percent would seemingly be needed. Given that EPA appears to use the GDP per capita growth rate as a proxy for the consumption per capita growth rate, it is unclear why EPA derives its consumption per capita rate as the EPA notes "in the past decade average global per capita growth rates have been closer to 2%,"[224] and over the longer term global per capita growth rates have been higher. Once again, such results call into question why the growth rate was forced to accommodate other assumptions, rather than the opposite, given that the growth rate is the most observable of all the terms in the Ramsey equation.

Fourth, EPA should clarify how it estimates the near-term consumption growth rate "net of baseline climate change damages," and provide a practical example of how it calculated the consumption growth rate "net of baseline climate change damages" beyond what is offered in Appendix 3 of the SC-GHG Report. Moreover, EPA should discuss how climate damages affect the growth rate. If damages are assumed to impact investment (which would affect future economic output, and thus the growth rate), this seems to contradict EPA's assumption that damage functions are specified in consumption-equivalent units.[225]

Fifth, given the assumption of a constant savings rate, EPA should explain the basis for the specific savings rate and the methodology used. Similarly, EPA should discuss how the SC-GHG estimates would change if the savings rate varied at the national or regional given historical trends.

- **Geographic scope and reporting** – EPA lists several reasons for selecting a global SC-GHG—including the potential impacts on U.S. citizens living abroad, U.S. overseas military bases and investments, and regional destabilization caused by climate change. However, non-US impacts estimated by the damage functions used by EPA do not correspond to these impact categories. For example, total non-US mortality damages are not a reasonable estimate of the impacts on U.S. citizens living abroad. Therefore, EPA should consider and discuss reasonable alternatives for estimating potential impacts to U.S. interests that occur in other countries. In

[221] Drupp *et al.* 2018. Discounting Disentangled. American Economic Journal: Economic Policy, 10 (4): 109-34.
[222] For the 1.5 percent consumption discount rate, EPA sets ρ to 0.01 percent and η to 1.02. For the 2 percent consumption discount rate, EPA sets ρ to 0.20 percent and η to 1.24. For the 2.5 percent consumption discount rate, EPA sets ρ to 0.46 percent and η to 1.42. Drupp *et al*.'s survey found that respondents' answers suggest a mean ρ value of 1.1 percent with a standard deviation of 1.47 and a median value of 0.5 percent.
[223] Drupp *et al.* 2018 at 61.
[224] SC-GHG Report at 22.
[225] *See* SC-GHG Report at 53.

addition, while EPA holds that not all spillover costs are properly attributed in regional breakdowns, as discussed further in Section III.c.1. below, the public would still benefit from SC-GHG estimates reported regionally, consistent with Circular A-4. EPA's SC-GHG Report also assumes that U.S. GHG mitigation activities, such as emissions pledges and the use of the global SC-GHG, engender international reciprocity. However, if EPA justifies the use of the global SC-GHG based on these factors, then the Agency should explain why its global emissions projection does not reflect globally coordinated action. Reasonable alternatives that maintain consistency between the geographic scope and the emissions trajectories should be considered and discussed.

- **Incorporation into regulatory cost-benefit analysis** – Given EPA's selection of a 1.5, a 2, and a 2.5 percent near-term discount rate, EPA's proposed SC-GHG discount rates no longer correspond to the typical regulatory consumption discount rate of 3 percent. Additionally, EPA's Ramsey discount rate approach further diverges from the constant discount rate approach used throughout federal cost-benefit analyses. Given that the announced revisions to Circular A-4[226] have not been finalized, API believes that it is inappropriate to incorporate EPA's new SC-GHG estimate in regulatory analysis until Circular A-4 is updated, as it is difficult to understand how EPA's SC-GHG approach for estimating climate benefits could be reasonably combined with other estimated benefits and cost streams discounted at different rates following standard A-4 guidance. For example, were EPA or another agency to use the EPA's SC-GHG estimates to present new benefit estimates in an RIA without updating the cost side of the ledger using the same near-term consumption discount rate used in the SC-GHG Report, the inconsistency between the discount rates used for benefits and costs would bias the cost-benefit analysis and undercut the rationality of the RIA's conclusions.

  EPA discusses the shadow price of capital, the preferred approach by Circular A-4, in Appendix 2 of the SC-GHG Report; however, EPA does not discuss whether or how the Agency plans to use this method in future cost-benefit analyses. To apply this method consistently, both benefits and costs must be adjusted in a similar manner. Whether this overall approach, or the revised discount rates themselves will improve cost-benefit analyses depends on whether and how Circular A-4 is updated to ensure consistency in how costs and benefits are estimated and compared. To avoid exacerbating inconsistencies, EPA should acknowledge this dependency and avoid using revised estimates until OMB guidance is updated, and all reviews are completed.

- **Underestimation of the SC-GHG** - EPA states that "The modeling implemented in this report reflects conservative methodological choices, and, given both these choices and the numerous categories of damages that are not currently quantified and other model limitations, the resulting SC-GHG estimates likely underestimate the marginal damages from GHG pollution."[227] This claim is repeated throughout EPA's SC-GHG Report. However, EPA should provide additional support for this assertion by listing and explaining the range of possible options and how the specific approach ultimately adopted by the Agency represents a conservative methodological choice. Repeating these assertions throughout the SC-GHG Report prior to completion of the IWG's peer review process may hamper objective analysis and may bias the IWG's review.

- **Market rates vs. purchase power parity** – EPA's SC-GHG Report states that "the shift to PPP-based projections in the RFF-SPs . . . represents another advancement in the science underlying the SC-GHG framework presented in this report."[228] However, Bressler and Heal (2022) contend that using "purchasing-power parity is incompatible with a pure Kaldor-Hicks approach."[229] Specifically, Bressler and Heal provide an example in which

[226] Joseph Biden Jr. 2021. Memorandum for the Heads of Executive Departments and Agencies; Modernizing Regulatory Review. The White House.
[227] SC-GHG Report at 2.
[228] SC-GHG Report 25.
[229] Bressler R., and Geffrey Heal. 2022. Valuing Excess Deaths Caused by Climate Change. National Bureau of Economic Research

a regulation would generate net costs when analyzed in PPP-adjusted dollars but would generate net benefits when analyzed using market exchange rates. EPA should therefore explain how using PPP-adjusted dollars is compatible with the federal government's overall approach to cost-benefit analysis.

c. The SC-GHG Report Should Fully and Explicitly Discuss the Limited Utility of the SC-GHG Estimates

EPA's SC-GHG Report avers that the SC-GHG estimates allow "analysts to incorporate the net social benefits of reducing emissions of greenhouse gases (GHG), or the net social costs of increasing such emissions, in benefit-cost analysis and, when appropriate, in decision-making and other contexts."[230] API agrees that from its earliest development by the IWG, the SC-GHG "was explicitly designed for agency use pursuant to E.O. 12866."[231] That is why the titles of each of the six TSDs the IWG published prior to the 2021 TSD disclaimed that they were "for Regulatory Impact Analysis under Executive Order 12866."[232]

While API agrees with the SC-GHG Report's statement that SC-GHG estimates are used in benefit-cost analysis, we believe EPA should clarify and describe the "decision-making and other contexts" the Agency believes may appropriately be based on SC-GHG estimates.[233] API agrees with the need to take action on climate change and we agree that agencies generally should weigh costs and benefits when considering such actions, but given the significant uncertainty and recognized malleability of SC-GHG estimates through modest changes to one or a few inputs, we cannot support expanded use of the Agency's or the IWG's SC-GHG estimates beyond their originally intended application in cost-benefit analysis. Indeed, in addition to, and in fact because of, the ease with which they can be "manipulated to reflect preferences, philosophies, assumptions, and so on,"[234] the SC-GHG estimates reflect such a broad range of uncertainty that in some contexts they may not effectively assist agencies' broad weighing of costs and benefits, as envisioned in E.O. 12866.

The SC-CH_4 values in EPA's SC-GHG Report and the IWG's 2021 TSD illustrate how agencies can struggle to use the estimates to determine whether a particular course of action will deliver more benefits than costs or *vice versa*. In the SC-GHG Report, the "nine separate distributions of estimates"[235] for avoided SC-CH_4 damages in 2030 range from $1,100 per metric ton to $3,700 per metric ton.[236] The 2021 TSD's estimates for avoided SC-CH_4 damages in 2030 range even more widely from $940 per metric ton to $5,200 per metric ton.[237] From a policy and regulatory perspective, the difference between $940 and $5,200 per metric ton or even $1,100 and $3,700 per metric ton is immense. A regulatory action that is imminently justifiable to mitigate damages estimated at the higher end of these ranges may be preposterous if proposed to avoid damages estimated at the lower end of these ranges.

"Such a wide range of . . . SC-CO_2 estimates is little more than a mathematical affirmation of the federal court's judgment that 'the value of carbon emissions reductions is certainly not zero.'"[238] "However, for the purpose the .

[230] SC-GHG Report at 1.
[231] Palenik Z. (2020). The Social Cost of Carbon in the Courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428.
[232] *See* 2010 TSD; May 2013 TSD; May 2013 TSD (revised); November 2013 TSD; August 2016a TSD (for CO_2); and August 2016b TSD (for Methane and Nitrous Oxide).
[233] API urged the IWG to provide the same clarification on multiple occasions.
[234] Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 366.
[235] SC-GHG Report at 66.
[236] SC-GHG Report at 68.
[237] 2021 TSD at 5.
[238] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

. $SC\text{-}CO_2$ was developed— . . .RIAs[] for US federal regulations—such a wide range of $SC\text{-}CO_2$ is not necessarily a problem."[239]

The Electric Power Research Institute ("EPRI") examined 65 federal rules and 81 subrules between 2008 and 2016 that utilized the IWG's $SC\text{-}CO_2$ estimates in their regulatory analyses.[240] EPRI found that "the inclusion of benefits from policy-induced CO_2 emissions changes does not change the sign of net benefits. In other words, the net benefits are positive with and without consideration of CO_2 reduction benefits."[241]

Thus, while the broad range of uncertainty inherent in the IWG's SC-GHG estimates would appear to preclude their use in most cost-benefit analyses, in practice, the estimates have been used in analyses in which the difference between costs and benefits was larger than the SC-GHG estimates' range of uncertainty. This demonstrates that for those actions with non-climate benefits that are already estimated to exceed costs by a substantial margin, the IWG's SC-GHG estimates' range of uncertainty will not matter.

The extent of uncertainty and speculation that besets the SC-GHG estimates developed by the IWG and EPA alike precludes their reduction to a single value, be it a central value or otherwise. The IWG's SC-GHG estimates "were developed . . . with a methodology to fit the specific purpose of a benefits estimate to be added to a regulatory impact analysis . . ."[242] While EPA's SC-GHG Report adopts a modular approach in lieu of reliance on the IAMs used by the IWG, the reality of the SC-GHG estimation process is "that a high degree of uncertainty is baked in and cannot reasonably be estimated away."[243] At best, this enterprise is capable of producing "a very wide range of potential" SC-GHG estimates.[244]

> In aggregate, the SCC estimates developed by the interagency working group and others represent a strange marriage of conventional economic-financial logic, arbitrary economic-financial logic, massively expansive biophysical phenomena, preference, and uncertainty management utilized to create a digestible input – a dollar amount – for use in the dominant cost-benefit analysis . . . framework.[245]

Moreover, the subjective judgements that are necessary inputs into the SC-GHG estimation process make the product of those modeling exercises malleable. Indeed, SC-GHG estimates "reflect ideology as much as they reflect the actual, long-term externality cost of climate change."[246] Thus, "[f]or these assumptions, the tools of science, economics, or statistics are incapable of providing a 'best' or single value."[247]

> [P]roducing a wide range of $SC\text{-}CO_2$ estimates is simply the best we can do using this methodology, and it is the best we will ever be able to do. The . . . Central $SC\text{-}CO_2$ is not an optimal price of CO_2 emissions or a best estimate of the benefits of CO_2 reductions. It is a noncomprehensive estimate

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239 Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).
240 Rose, S and J. Bistline, "Applying the Social Cost of Carbon: Technical Considerations." EPRI Palo Alto, CA: 2016. 300200f4659.
241 Rose, S and J. Bistline, "Applying the Social Cost of Carbon: Technical Considerations." EPRI Palo Alto, CA: 2016. 300200f4659.
242 Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).
243 Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 364-5.
244 Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).
245 Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 348.
246 Taylor, A. (2018). Why the Social Cost of Carbon is Red Herring. Tulane Environmental Law Journal, 31(2), 345-372, 369.
247 Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).

of the benefits of GHG reductions using one set of assumptions that is arguably defensible given the theoretical and methodological challenges associated with the approach.[248]

In addition to the methodological limitations precluding the use of the SC-GHG estimates in royalties, subsidies, fees, or applications that require a single value or narrow range of uncertainty, there are legal, statutory, and practical constraints on more expansive use of SC-GHG estimates as well. Indeed, courts have generally only upheld agencies' use of the SC-GHG estimates in the context of cost-benefit analyses.[249]

While some courts have held that agencies must estimate the costs of GHG emissions when assessing impacts of their proposed actions under the National Environmental Policy Act ("NEPA"), the agencies' impact assessments in those cases typically included cost-benefit analyses that are not required by NEPA.[250] In other words, because the agencies there estimated quantified benefits of certain actions, they also had to estimate quantified costs including of GHG emissions. In many other cases, courts have held that agencies have no obligation to use the SC-GHG estimates in analyzing impacts under NEPA.[251] Indeed, many of these courts took favorable views of agency determinations that SC-GHG estimates are ill-suited for NEPA analyses based on uncertainty ranges or otherwise.[252] Courts have generally taken a similar view to the Federal Energy Regulatory Commission's ("FERC's") prior position that the SC-GHG estimates' broad variability range makes them unsuited for public interest determinations[253] under the Natural Gas Act.[254] And in the context of collecting royalties and other financial obligations related to the leasing, production, and sale of minerals from federal and Indian lands, the federal government is affirmatively prohIbited from considering the SC-GHG estimates.[255]

Indeed, regardless of whether the Administration continues to rely on the IWG's estimates or those newly proffered by EPA in the SC-GHG Report, the SC-GHG estimates' broad range of variability and uncertainty render them inappropriate for use in any project-level or site-specific application. In addition, while analyses at these scales might be capable of monetizing some impacts (such as projected climate impacts), partial monetization is not advisable for several reasons. First, it could be interpreted as emphasizing or de-emphasizing the monetized impact, even though there is no basis on which to conclude that a monetized impact is more or less significant than a non-monetized impact. Second, monetized benefits and costs are only meaningful when they are compared to one another in aggregate.

These considerations illustrate the material distinction between formalized cost-benefit analysis in the regulatory context and other types of analysis. Whereas monetization is essential for regulatory analyses, it is potentially misleading outside this application for reasons discussed above. Notably, this material distinction is also embodied

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[248] Kaufman, N. (2018). The Social Cost of Carbon in Taxes and Subsidies, Part 1: The Current Use of Estimates. Center for Global Energy Policy, Columbia SIPA (March 2018).
[249] Palenik, Z. (2020). The social cost of carbon in the courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428, 416.
[250] *High Country Conservation Advocates v. U.S. Forest Serv.*, 52 F. Supp. 3d 1174,1181, 1184 (D. Colo. 2014); *See also Mont. Envtl. Info. Ctr. v. U.S. Office of Surface Mining*, 274 F. Supp. 3d 1074, 1096-98 (D. Mont. 2017); *See also Citizens for a Healthy Community v. BLM*, 377 F.Supp. 3d 1223 (D. Col. 2019); *Contrast with WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41; *See also* Palenik, Z. (2020). The social cost of carbon in the courts: 2013-2019. New York University Environmental Law Journal, 28(3), 393-428, 415.
[251] *See Wildearth Guardians v. Bernhardt*, No. 1:19-cv-00505-RB-SCY (D. N.M. Nov. 19, 2020); *See also 350 Montana v. Bernhardt*, 443 F. Supp. 3d 1185 D. Mont. 2020); *See also Citizens for a Healthy Cmty v. U.S. Bureau of Land Mgmt.*, 377 F. Supp. 3d 1223, 1239-40 (D. Colo. 2019); *See also WildEarth Guardians v. Zinke*, 368 F. Supp. 3d 41, 76 (D.D.C. 2019); *See also Wilderness Workshop v. U.S. Bureau of Land Mgmt.*, 342 F. Supp. 3d 1145, 1159 (D. Colo. 2018); *High Country Conservation Advocates v. Forest Service*, 333 F. Supp. 3d 1107 (D. Colo. 2018); *See also W. Org. of Res. Councils v. U.S. Bureau of Mgmt*., No. CV 16-21-GFBMM, 2018 WL 1475470, at *13 (D. Mont. Mar. 26, 2018).
[252] *See Wildearth Guardians v. Bernhardt*, No. 1:19-cv-00505-RB-SCY (D. N.M. Nov. 19, 2020); *See also 350 Montana v. Bernhardt*, 443 F. Supp. 3d 1185 D. Mont. 2020).
[253] *See* Natural Gas Act,15 U.S.C. § 717f(a), (c) (2012).
[254] *See, EarthReports, Inc. v. Fed. Energy Reg. Comm'n*, 828 F.3d 949,. 953-54 (D.C. Cir. 2016); *See also Sierra Club v. Fed. Energy Regulatory Comm'n*, 867 F.3d 1357, 1375 (D.C. Cir. 2017) (remanding to FERC for a discussion of whether it still holds the *EarthReports* position); *See also Sierra Club v. Fed. Energy Regulatory Comm'n*, 672 Fed. Ap 'x 38 (D.C. Cir. 2016).
[255] *See Wyoming v. Jewell*, No. 2:16-CV-0285-SWS (Oct. 10, 2020); *See also* 86 Fed. Reg. 31,196, 31,206 (June 11, 2021).

in E.O. 12866, which distinguishes between "regulatory actions" and "significant regulatory actions" based in part of the projected scale of impact.[256] For each "significant" proposed action, the issuing agency is required to provide a cost-benefit analysis. Thus, existing regulatory guidance essentially equates significance with the need for cost-benefit analysis, which in turn, implies full monetization of costs and benefits. While (as discussed above), there are inherent limits to the usefulness of SC-GHG estimates in rulemaking, consideration of SC-GHG values is sensible in situations where all costs and benefits are monetized. Consideration of the SC-GHG estimates is not appropriate in instances where only a subset of impacts can be monetized; accordingly, restricting its use to significant regulatory actions ensures consistency with this principle.

d. **The SC-GHG Report Needlessly Limits the Utility of EPA's SC-GHG Estimates by Failing to Present Domestic SC-GHG Estimates Alongside Global Estimates**

In order to conduct a valid and legally-defensible cost-benefit analysis, agencies must ensure that they weigh costs and benefits of the same scale and of the same type. Therefore, consistent with API's repeated requests to the IWG, API recommends that EPA's SC-GHG Report present domestic SC-GHG estimates alongside global estimates. Indeed, we believe that, absent a clear congressional directive otherwise, agency cost-benefit analyses should be constructed to weigh domestic costs against domestic benefits. By doing so, agencies can better ensure that projected domestic impacts alone justify the costs to be imposed on domestic industries. When agencies have failed to do so and weighed domestic costs against global benefits, they have effectively put their thumb on the scale in favor of regulatory action. Such an analysis is not only inconsistent with basic economic principles it overlooks "the more prosaic commonsense notion that Congress generally legislates with domestic concerns in mind."[257]

Given that EPA claims to have utilized, and is taking comment on, the SC-GHG Report as part of the Proposed NSPS Revisions, the CAA provides a particularly relevant example of why the geographic scope of agencies' regulatory analyses should reflect the intended scope under which the regulation is proposed or promulgated.[258] In CAA Section 101(b)(1), Congress expressly stated that the statute's purpose is to "protect and enhance the quality of the *Nation's* air resources so as to promote the public health and welfare and the productive capacity of *its population*."[259] By focusing on "the Nation" and "its population," Congress clearly demonstrated that it enacted the CAA to affect domestic air quality.

This interpretation of the CAA is not new, nor does it fail to reflect the global nature of climate change. Indeed, EPA relied on this interpretation when it issued the highly important Endangerment Finding on which multiple federal climate change regulatory actions have been based.[260]

In addition to the clear inferences that can be drawn from Congress' statements of statutory intent, the text of specific provisions of the statute confirms that Congress intended to limit the reach of the Act to domestic effects, unless it expressly provided otherwise. In only two discrete instances, Congress explicitly addressed the foreign effects of domestic air emissions in the CAA.

[256] *See* E.O. 12866 at Sec. 3.
[257] *RJR Nabisco, Inc. v. Eur. Cmty.*, 136 S. Ct. 2090, 2100 (2016).
[258] 87 Fed. Reg. at 74,713.
[259] CAA § 101(b)(1) (emphasis added).
[260] *See* Final Rule, Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the CAA, 74 Fed. Reg. 66496, 66514 (Dec. 15, 2009) ("[T]he primary focus of the vulnerability, risk, and impact assessment is the United States").

First, in Title I of the Act, Congress authorized EPA to consider the foreign effects of domestic air emissions within the delineated framework of Section 115. There, Congress defined the process for EPA to evaluate and address reports of domestic air pollution possibly affecting public health or welfare in a foreign country.[261] Critically, this only applies when the Administrator finds there is "reciprocity" such that "the United States essentially [has] the same rights with respect to the prevention or control of air pollution occurring in that country as" Section 115 gives to the foreign country.[262]

Second, in Title VI of the CAA, Congress addressed the global impacts of domestic stratospheric ozone emissions by, among other actions, listing ozone-depleting chemicals of concern, establishing reporting requirements for manufacturers and other entities, and phasing out the production of certain chemicals.[263] Congress expressly enacted Title VI in 1990 in order to implement the Montreal Protocol on Substances that Deplete the Ozone Layer, an international treaty signed by the United States, which addresses stratospheric ozone.[264]

These two discrete provisions (Section 115 and Title VI) represent the full extent of EPA's authority to consider the international benefits of domestic regulation. Critically, these provisions demonstrate that, when Congress chose to allow the Agency to consider foreign impacts of domestic regulation, it said so expressly. These two provisions also reflect the very narrow purpose for which Congress allowed EPA to consider foreign impacts of domestic regulation. Both provisions deal with international agreements under which the United States and one or more foreign nations make reciprocal commitments to impose regulations within their borders that confer benefits outside their borders and/or to the other party.

In these two narrow circumstances, the United States is the beneficiary of EPA's action and also the foreign nation's reciprocal regulatory action. As such, while foreign impacts are considered, their consideration is solely intended to inform regulatory decisions seeking to maximize domestic benefits of reciprocal regulatory actions. The executive branch has ample authority to act for the benefit of foreign nations, but the CAA is generally not one of the statutes that confers that authority. With the exception of these two discrete provisions, the CAA arguably precludes EPA from weighing international benefits against domestic costs.[265]

In addition to the limitations that the CAA places on EPA specifically, OMB guidance applies these same principles government-wide. In support of limiting the use of international benefits for justifying regulation, OMB directs agencies developing regulatory analyses to focus on the "benefits and costs that accrue to citizens and residents of

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[261] CAA § 115(a)-(b).
[262] CAA § 115(c).
[263] EPA, 1990 CAA Amendment Summary: Title VI (Jan. 4, 2017), https://www.epa.gov/clean-air-act-overview/1990-clean-air-act-amendment-summary-title-vi.
[264] 42 U.S.C. § 7671m(b) ("This subchapter as added by the CAA Amendments of 1990 shall be construed, interpreted, and applied as a supplement to the terms and conditions of the Montreal Protocol.").
[265] Settled principles of statutory interpretation further confirm that Congress did not intend to authorize EPA to rely on the foreign effects of U.S. emissions in promulgating regulations under the CAA. For one, statutes are construed to give effect to all provisions. *See, e.g., Hibbs v. Winn*, 542 U.S. 88, 101 (2004) ("A statute should be construed so that effect is given to all its provisions, so that no part will be inoperative or superfluous, void or insignificant….") (citations omitted). Section 115 would effectively be a nullity if EPA read the Act to provide the Agency with the authority to consider effects of domestic emissions on foreign countries without following the Section 115 process. Moreover, it is also a well-settled canon that if Congress addressed an issue in one provision, its failure to address that same issue elsewhere confirms its limited intent. *See, e.g., Russello v. United States*, 464 U.S. 16, 23 (1983) ("[W]here Congress includes particular language in one section of a statute but omits it in another section of the same Act, it is generally presumed that Congress acts intentionally and purposely in the disparate inclusion or exclusion.") (citations omitted).

the United States"[266] and directs agencies which "choose to evaluate a regulation that is likely to have effects beyond the borders of the United States" to report those impacts "separately."[267] OMB's guidance further states that an agency's cost-benefit analysis "should focus on benefits and costs that accrue to *citizens and residents of the United States*."[268]

Notwithstanding that OMB Circular A-4 mandates agency consideration of domestic costs and benefits while simply allowing for optional consideration of non-U.S. benefits, EPA's SC-GHG Report omits any calculation of domestic benefits. In lieu of this important, and arguably mandatory presentation of domestic benefits, the SC-GHG Report merely offers the EPA's justification for its absence.[269] While these justifications are perhaps sufficient to support the EPA's decision to present global benefits in the SC-GHG Report, none explain the Agency's refusal to also present an estimate of domestic benefits alongside the global value.

For instance, the IWG argues that analyzing the global benefits of U.S. regulatory actions can help generate reciprocal actions from other countries and "allows the U.S. to continue to actively encourage other nations . . . to take significant steps to reduce emissions."[270] Even assuming such effect occurs, the goal of the SC-GHG estimation process should not be the development of tools to aid in international negotiations or which help the U.S. "actively encourage" reciprocal actions on climate change; President Biden required use of the "best available economics and science"[271] to estimate as accurately as possible the societal costs of adding a small increment of GHG into the atmosphere in a given year. To the extent EPA is attempting to assume the IWG's assigned role of developing SC-GHG estimates, the Agency must also assume the obligation to dispassionately and objectively estimate the SC-GHGs using "best available economics and science."[272] And that obligation cannot be construed to encompass an advocacy role. Even if it were reasonable for EPA's interest in advocating for intergovernmental cooperation to shape how it estimates the SC-GHG, the EPA's SC-GHG Report provides no explanation why that advocacy role would be undermined by the presentation of domestic benefits *alongside global benefits*.

EPA also offers that:

> The global nature of GHG pollution and its impacts means that U.S. interests are affected by climate change impacts through a multitude of pathways and these need to be considered when evaluating the benefits of GHG mitigation to the U.S. population.[273]

Although the U.S. could be adversely impacted by potential climate change damages that could occur in other countries, it does not follow that the EPA must therefore include the potential *damages in those other countries* as part of the SC-GHG estimate. Rather, the Agency should include in the SC-GHG estimates the potential *domestic impact* of those reasonably projected extraterritorial climate damages. As explained by the NASEM:

> Correctly calculating the portion of the SC-CO_2 that directly affects the United States involves more than examining the direct impacts of climate that occur within the country's physical borders . . .

[266] OMB, Circular A-4, at 15.
[267] OMB, Circular A-4, at 15.
[268] OMB, Circular A-4, at 15 (emphasis added).
[269] *See* SC-GHG Report at 10-15
[270] SC-GHG Report at 14.
[271] E.O. 13990 at Sec. 5(b)(ii)(D).
[272] E.O. 13990 at Sec. 5(b)(ii)(D). Notably, and as previously discussed, E.O. 13990 expressly assigned the SC-GHG estimation development process to the IWG and precluded agencies from developing and using their own values.
[273] SC-GHG Report at 11.

> Climate damages to the United States cannot be accurately characterized without accounting for consequences outside U.S. borders.[274]

In other words, regardless of whether climate change imposes costs on the U.S. directly or indirectly through potential damages in other countries, the costs EPA should be attempting to characterize are those anticipated to be borne by the U.S. and its citizens. Thus, the global nature of climate change is consistent with and supported by the presentation of domestic benefits in the SC-GHG estimates. And the global nature of this issue certainly does not explain why the domestic benefits should not at least be presented alongside projections of global benefits.

EPA's final rationale for declining to present domestic benefits alongside global values is that there are relatively few region- or country-specific SC-GHG estimates or models with sufficient resolution to estimate SC-GHG benefits on a country-specific basis.[275] At the same time, EPA has largely limited its own consideration of damage functions to those that can be specified at the national or sub-national level, suggesting that domestic impacts could be reasonably estimated in two of the three frameworks adopted.[276] Although we agree that there is a high level of uncertainty in the regional or country-specific SC-GHG estimates, we believe it is inconsistent for EPA to use this uncertainty to rationalize its decision to decline to provide any SC-GHG estimates other than global, particularly given EPA's decision to severely restrict consideration of damage functions to precisely those that provide such information. Uncertainty and speculation pervade every aspect of the SC-GHG estimates, and the Agency should explain why such uncertainty provides a valid basis to decline to render estimates in this instance, but presents no barrier in every other respect.

It is also increasingly inaccurate for EPA to cite the overall paucity of literature on regional and country-specific SC-GHG estimates. As noted by the NASEM in 2017:

> Estimation of the net damages per ton of CO_2 emissions to the United States alone, beyond the approximations done by the IWG, is feasible in principle; however, it is limited in practice by the existing SC-IAM methodologies . . .[277]

Indeed, EPA's SC-GHG Report identifies a number of new models and academic efforts that have enhanced our ability to model SC-GHG benefits with greater spatial resolution.[278] While these country-specific estimates remain highly uncertain and divergent, they all broadly agree that the SC-GHG in the U.S. is a small fraction of the SC-GHG Report's estimates of the global SC-GHG.

Although country-specific SC-GHG estimates remain quite imprecise, they are highly relevant because EPA and other agencies should not adopt rules which could impose massive costs on the U.S., but for which the claimed benefits primarily accrue overseas—certainly not without a clear and explicit directive from Congress. EPA's assertion that rule writers and policymakers use only the global SC-GHG estimates in cost-benefit analysis results in

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[274] NASEM 2017 at 52-53.
[275] SC-GHG Report at 77-80.
[276] SC-GHG Report at 39 ("Based on a review of available studies using these approaches, the SC-GHG estimates presented in this report rely on three damage functions. They are: 1. a subnational-scale, sectoral damage function estimation (based on the Data-driven Spatial Climate Impact Model (DSCIM) developed by the Climate Impact Lab (CIL 2022, Carleton et al. 2022, Rode et al. 2021)), 2. a country-scale, sectoral damage function estimation (based on the Greenhouse Gas Impact Value Estimator (GIVE) model developed under RFF's Social Cost of Carbon Initiative (Rennert et al. 2022b)), and 3. a meta-analysis-based global damage function estimation (based on Howard and Sterner (2017)).").
[277] NASEM 2017 at 53.
[278] SC-GHG Report at 77-80.

a significant misalignment of costs and benefits, particularly for regulatory actions, like the Proposed NSPS Revisions, that are promulgated pursuant to the CAA.

As such, API's modest recommendation, which we have also previously voiced to the IWG, is not that the federal government abandon the global SC-GHG estimates, but that it simply present domestic SC-GHG estimates alongside global values. This approach would allow risk managers to more readily align the costs with the benefits. Consistent with OMB guidance, the costs of a rule for entities in the U.S. should be presented in comparison with the benefits occurring in the U.S.

IV. CONCLUSION

API appreciates the opportunity to provide these comments on EPA's SC-GHG Report. We hope this comment opportunity is the first step toward a more open and transparent process for developing SC-GHG estimates and the judgment and assumptions used to develop and portray those estimates.

API shares the Biden Administration's goal of reducing economy-wide GHG emissions. And while API appreciates EPA's decision to accept comments specifically on the Agency's SC-GHG Report, EPA's unilateral development of SC-GHG estimates raises a number of questions and concerns the anticipated role of these new estimates in Agency rulemaking, and the SC-GHG Report's apparent inconsistency with the Biden Administration's stated intent to collaboratively and transparently develop and revise SC-GHG estimates through the IWG.

President Biden's issuance of E.O. 13990 on his first day in office reflects the importance of the SC-GHG estimates to our nation's climate policies and regulations. Given the importance of these estimates, we believe EPA should have transparently engaged and collaborated with interested stakeholders throughout its process to revise and update each of the four modules on which the SC-GHG Report based its revised estimates, rather than postpone comment until each module had been updated and the SC-GHG Report had been fully drafted. Moreover, given the extent of the changes encompassed in EPA's SC-GHG Report and the extensive new data and analyses on which the report purports to be based, API believes that the current 69-day comment period is wholly insufficient for soliciting detailed feedback from informed stakeholders.

API is similarly concerned that EPA's docket for this rulemaking does not include all of the studies and data on which EPA purports to have based its SC-GHG Report, and therefore fails to provide interested parties sufficient information on which to base detailed comments. In fact, EPA has not even clearly explained why it developed the SC-GHG Report or how it intends the SC-GHG Report's estimates to be used. Nonetheless, where possible, API has tried to provide EPA relevant analysis and constructive recommendations for improving the reliability and utility of the SC-GHG Report and the estimates therein. We did so, not only with the intent of improving the SC-GHG estimates and the process through which they are developed, but with the hope that by providing credible analysis and constructive feedback, EPA would more fully recognize the benefit of engaging stakeholders in a more open, data-driven, and collaborative process.

API recognizes the need to confront the challenges of climate change. However, regardless of whether they are developed by the IWG or EPA alone, inherent limitations in estimates of the SC-GHG significantly constrain their utility in rulemaking. Indeed, SC-GHG estimates may only have utility with respect to broad considerations of costs and benefits in analyses under E.O. 12866, and not in rules that require the SC-GHG to be expressed as a single value or with a narrow range of uncertainty.

Thank you again for your consideration of these comments. If you have any questions or would like to discuss these comments, please feel free to contact Andrew Baxter at (202) 268-2800 or baxtera@api.org.

Sincerely,

Andrew Baxter
Economic Advisor, Policy Analysis
American Petroleum Institute

ANNEX D: API Barnett and Bakken Mantis Field Studies

American Petroleum Institute Mantis™ Field Study

Final Report | Revision 1.0

September 2023

PROJECT 0040-001

API BARNETT

PREPARED BY
Providence Photonics, LLC | 1201 Main Street, Baton Rouge, LA 70802

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Introduction

Providence Photonics, LLC (Providence) has developed a method to remotely measure the performance of an industrial flare using Video Imaging Spectral Radiometry (VISR). The VISR method provides five flare performance metrics: combustion efficiency (CE), smoke index (SI), flame stability (FS), flame footprint (FF), and fractional heat release (FH). The VISR method is incorporated into Providence's Mantis™ flare monitoring product (Mantis).

Providence used the Mantis device to conduct a flare measurement in the Barnett regions for American Petroleum Institute (API) in September of 2023. The measurements were performed from September 11th, 2023 to September 16th, 2023. This report summarizes the Mantis data and associated findings from the study.

Background

The VISR method utilizes a multi-spectral mid-wave infrared imager to measure the radiance from both hydrocarbons being combusted and carbon dioxide (CO_2) as complete combustion product, and use that information to determine the combustion efficiency. The method was designed to be a continuous and autonomous remote flare monitor, but in this study it was deployed as a mobile technology for a short-term measurement. ***Figure 1*** below shows the Mantis device deployed at one of the sites during the Barnett study.

Figure 1: Mantis deployed during API field survey in Barnett region.

1. COMBUSTION EFFICIENCY (0 TO 100%): Combustion efficiency (CE) is a measure of the relative concentration of hydrocarbon vs. carbon dioxide in the post combustion gas plume. If there is no hydrocarbon present in the post combustion gas plume, then CE is 100%. CE should not be confused with Destruction and Removal Efficiency (DRE). The difference between these two metrics is discussed in **Appendix C**. While CE is directly measured by the VISR method, DRE is derived using correlations established through extractive sampling as discussed in **Appendix C**.
2. SMOKE INDEX (0 TO 10): Smoke index (SI) is a unit-less number which indicates the degree of visible emissions within the combustion envelope. A SI of 0 means no visible emissions are present while a SI of 10 means the flare has heavy black smoke. While SI only represents the degree of visible emissions within the combustion envelope, it is generally correlated to opacity and a SI above 3 generally indicates that some visible emissions are likely present outside of the combustion envelope.
3. FLAME FOOTPRINT (FT^2): Flame footprint (FF) is a measure of the flame size in square feet. It is not necessarily correlated to the visible flame size as the FF is determined by the radiance, not the visible flame. Note that the orientation of the flame will impact the FF as the depth of the flame will change with viewing angle.
4. FRACTIONAL HEAT RELEASE (BTU/HR): Fractional Heat Release (FH) is a measure of the heat released from flare combustion in the spectral bands monitored by the Mantis flare monitor. Although it is not a measure of the total heat release across the entire energy spectrum, FH is expected to be correlated to the total heat release.
5. FLAME STABILITY (0 TO 100%): Flame stability (FS) is a measure of the change in radiance measured by the Mantis flare monitor in a 1-second interval. A FS of 100% indicates a flame that has a constant radiance. A low FS value (generally lower than 80%) indicates a flame with significant radiance fluctuation within 1 second interval, suggesting a less stable flame. Variability on a longer time scale will not be described by the flame stability metric.

Data Quality Indicators

The VISR method has two important data quality indicators (DQI) to assess the quality of the measurement. The first is the number of pixels in the flame combustion envelope, the outer layer of the flame where the combustion process has ceased. The VISR method requires at least 30 pixels to accurately determine the performance metrics of the flame. The VISR device has a fixed focal length, so the number of pixels in the flame is determined by the size of the flame and the distance from the VISR imager to the flame. For this study, any measurements with less than 30 pixels were removed from the summary tables and **Appendix A**.

The second important DQI is the Smoke Index level. As the smoke index increases above 3.0 (this threshold may vary within a range of 1-2 depending on specific flares), visible emissions are generally present in the flame. When visible emissions become significant, the SI value will climb even higher to a maximum value of 10 for thick black smoke. Testing has shown that SI values above 3.0 may cause a small negative bias on the CE measurement by VISR (< 1%) and SI values above 5 may cause a significant negative bias to CE measured by VISR, as confirmed by testing with an extractive sampling method as a control (note that in the extractive sampling method, carbon soot is not included in the CE calculation). Any data points with a smoke index above 5 were removed from the summary tables and **Appendix A** as they are considered outside of method limits.

Observations

The following sections describe field observations and comparisons derived from the dataset.

Aggregate results

The flare measurements included sites from three companies ([redacted] In total, there were 39 individual flares measured. The distribution of the DRE measurements is represented in ***Figure 2*** below.

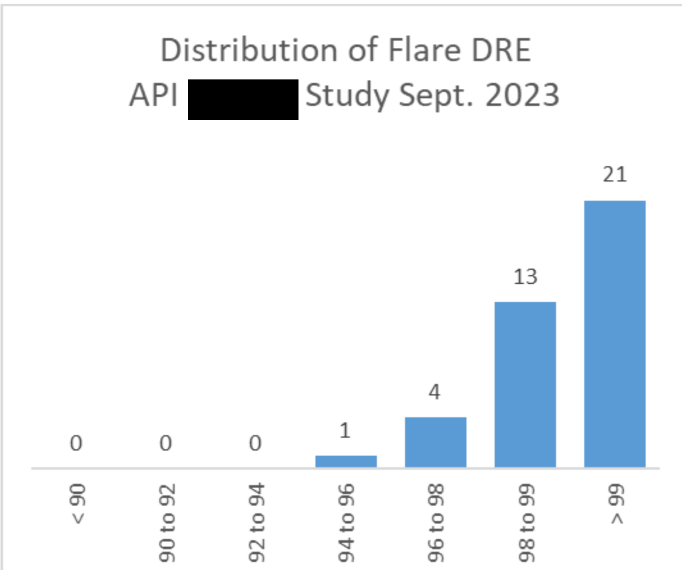


Figure 2: HP and LP flare tips on Green Canyon 254.

Summary

Providence conducted flare measurements on 39 flares in the Barnett region from September 11th, 2023 to September 16th, 2023. The measurement summaries are provided in ***Table 1*** and ***Appendix A*** with the distribution of the measurements provided in ***Figure 2***. Overall efficiencies across the study were high, with 87% of the flares demonstrating a DRE above 98%.

References

1. Yousheng Zeng, Jon Morris & Mark Dombrowski (2015) Validation of a new method for measuring and continuously monitoring the efficiency of industrial flares, Journal of the Air & Waste Management Association, 66:1, 76-86, DOI: 10.1080/10962247.2015.1114045

2. Yousheng Zeng, Jon Morris. (2019, April 2nd). *Precision and Accuracy of the VISR Method for Flare Monitoring*. Air Quality Measurement Methods and Technology, Durham, North Carolina, United States.

Appendix A: Results

Date/Time				Description		Conditions				Efficiency (%)					Smoke Index (0-10)				Flare Footprint (m^2)				Fractional Heat (MMBTU/HR)				Flame Stability (%)			
ID	Date	Start Time (Local)	End Time (Local)	Company	Location	Distance (m)	Temp (°C)	RH (%)	WS (mph)	CE Avg	DRE Avg	CE Min	CE Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD
1	9/11 -9/16	7:57 AM	8:13 AM			54	26	52	2-4	98.88	99.51	97.84	99.45	0.27	0.34	0.01	1.24	0.23	7.4	1.4	18.4	4.1	0.08	0.00	0.25	0.06	91.6	0.1	100.0	8.1
2		9:56 AM	10:12 AM			76	29	42	2-4	99.20	99.53	90.82	100.00	1.38	2.49	1.09	6.21	0.69	56.9	31.4	80.2	10.5	3.19	1.24	5.15	0.81	93.1	75.9	100.0	4.0
3		10:56 AM	11:11 AM			61	31	40	0-2	99.27	99.82	98.16	99.87	0.24	0.22	0.02	0.57	0.14	13.8	0.2	39.9	10.3	0.26	0.00	1.11	0.28	88.4	0.1	100.0	14.2
4		12:29 PM	12:45 PM			69	34	33	2-4	98.98	99.58	97.11	99.83	0.44	0.63	0.20	1.24	0.13	12.9	9.3	16.5	1.4	0.28	0.09	0.35	0.02	94.1	75.8	100.0	3.2
5		1:47 PM	2:04 PM			109	35	29	2-4	98.98	99.58	97.71	99.99	0.37	0.90	0.33	1.53	0.22	18.0	11.3	38.7	2.3	0.42	0.32	0.52	0.03	95.7	59.1	100.0	2.7
6		2:41 PM	2:56 PM			405	36	27	4-6	96.96	97.86	88.75	100.00	1.36	0.75	0.07	4.14	0.61	180.1	62.4	681.0	49.0	1.29	0.12	4.99	0.76	80.8	0.1	100.0	11.7
7		8:15 AM	8:31 AM			97	18	77	2-4	99.40	99.79	94.00	100.00	0.65	1.50	0.69	2.35	0.22	147.9	87.4	182.4	17.2	3.91	1.19	5.24	0.78	95.5	49.4	100.0	2.8
8		9:30 AM	9:45 AM			136	19	77	2-4	98.40	99.09	96.49	100.00	0.74	0.98	0.05	1.58	0.19	101.7	18.2	149.0	19.3	1.85	0.07	2.63	0.36	95.1	74.3	100.0	2.7
9		11:18 AM	11:33 AM		I	116	20	79	2-4	98.61	99.23	96.54	100.00	0.80	1.22	0.78	1.97	0.20	95.7	76.2	125.2	6.7	2.50	1.82	3.08	0.26	95.4	82.9	100.0	2.1
10		12:26 PM	12:42 PM			124	19	82	2-4	98.34	99.05	95.76	99.91	0.58	0.69	0.21	1.28	0.21	28.8	13.6	67.4	7.2	0.45	0.12	0.82	0.16	96.0	70.6	100.0	2.1
11		1:14 PM	1:30 PM			90	20	78	2-4	98.67	99.31	96.83	100.00	0.63	0.80	0.05	1.53	0.27	31.3	3.1	53.3	9.3	0.65	0.01	1.37	0.29	92.4	35.1	100.0	6.5
12		3:11 PM	3:28 PM			116	20	80	2-4	99.99	99.99	98.63	100.00	0.27	4.30	1.28	9.56	1.35	76.5	33.6	133.8	18.4	2.41	0.50	8.43	1.20	90.2	47.7	100.0	5.0
13		9:09 AM	9:17 AM			17	20	82	0-2	97.88	98.66	92.09	99.29	0.73	0.48	0.15	1.01	0.15	0.9	0.3	1.7	0.3	0.02	0.00	0.04	0.01	90.8	0.1	100.0	8.5
14		10:03 AM	10:18 AM			21	20	82	0-2	98.07	98.82	93.01	99.56	0.97	0.49	0.11	1.23	0.16	0.5	0.1	1.9	0.5	0.01	0.00	0.02	0.01	95.0	65.4	100.0	2.9
15		12:34 PM	12:50 PM			38	22	92	0-2	98.57	99.23	93.14	100.00	0.66	0.51	0.07	1.66	0.22	3.0	0.6	8.1	1.1	0.07	0.00	0.16	0.03	84.3	0.1	100.0	12.4
16		1:38 PM	1:40 PM			37	26	68	2-4	93.91	95.28	85.94	99.79	3.15	0.07	0.04	0.28	0.04	0.3	0.0	1.0	0.2	0.00	0.00	0.02	0.00	50.1	0.1	100.0	32.1
17		2:09 PM	2:24 PM			41	28	45	0-2	97.37	98.23	95.35	98.89	0.46	0.23	0.15	0.78	0.06	0.7	0.3	1.4	0.2	0.01	0.01	0.03	0.00	93.1	75.1	100.0	4.1
18		4:43 PM	4:58 PM			23	31	51	0-2	98.23	98.95	95.91	99.75	0.63	0.21	0.09	0.51	0.06	0.9	0.2	1.7	0.3	0.02	0.01	0.04	0.01	96.2	39.5	100.0	3.1
19		10:39 AM	10:53 AM			94	31	29	0-2	98.11	98.80	92.86	100.00	1.17	0.93	0.43	1.74	0.28	11.7	8.9	32.9	1.5	0.25	0.18	0.35	0.03	95.4	44.2	100.0	3.3
20		12:53 PM	1:08 PM			32	33	36	0-2	95.10	96.29	84.81	99.75	4.41	0.06	0.03	0.12	0.01	0.6	0.0	1.0	0.2	0.01	0.00	0.01	0.00	91.7	0.1	100.0	8.4
21		1:21 PM	1:36 PM			46	32	36	0-2	98.89	99.49	96.33	100.00	0.49	0.95	0.20	2.51	0.31	3.6	0.5	8.4	0.7	0.07	0.00	0.14	0.02	86.5	40.7	100.0	8.7
22		1:58 PM	2:13 PM			44	34	30	0-2	99.31	99.74	90.77	99.99	0.88	0.02	0.01	0.05	0.01	0.9	0.1	1.3	0.2	0.00	0.00	0.01	0.00	85.5	32.7	100.0	8.4
23		2:52 PM	3:07 PM			42	35	27	2-4	98.43	99.11	85.65	99.83	1.80	0.05	0.02	0.66	0.04	0.4	0.0	1.0	0.2	0.00	0.00	0.01	0.00	78.0	0.1	100.0	21.2
24		8:25 AM	8:41 AM			24	21	84	0-2	97.28	98.15	93.97	98.72	0.60	0.68	0.49	0.90	0.08	1.6	0.7	2.0	0.2	0.03	0.02	0.04	0.00	95.1	83.4	100.0	2.5
25		9:27 AM	9:43 AM			10	27	63	2-4	98.21	98.94	96.60	99.98	0.49	0.73	0.23	1.28	0.21	0.3	0.1	1.2	0.2	0.01	0.00	0.05	0.01	92.4	60.2	100.0	4.5
26		10:09 AM	10:40 AM			35	24	71	2-4	98.33	99.04	96.13	99.58	0.57	0.55	0.11	1.07	0.17	1.3	0.0	2.2	0.4	0.01	0.00	0.03	0.01	67.0	0.1	100.0	21.9
27		12:22 PM	12:36 PM			43	29	60	0-2	98.22	98.89	85.50	100.00	1.82	1.47	0.59	4.11	0.57	16.6	7.8	23.1	2.7	0.66	0.21	1.07	0.19	90.7	19.4	100.0	5.5
28		1:05 PM	1:21 PM			52	34	40	0-2	98.65	99.31	96.87	99.66	0.38	0.26	0.02	0.90	0.15	14.3	0.3	32.7	8.2	0.27	0.00	0.91	0.20	88.8	0.1	100.0	13.0
29		2:15 PM	2:30 PM			69	33	49	2-4	97.81	98.60	93.79	100.00	1.27	2.25	0.86	7.96	0.91	39.9	22.2	64.7	6.7	1.60	0.62	3.59	0.45	89.9	53.6	100.0	5.7
30		3:24 PM	3:41 PM			30	30	49	2-4	98.71	99.35	96.51	100.00	0.50	0.65	0.13	1.34	0.19	2.8	0.5	4.3	0.8	0.04	0.00	0.08	0.02	76.6	0.1	100.0	14.3
31		8:45 AM	9:00 AM			27	21	68	0-2	98.03	98.79	89.51	99.64	1.12	0.21	0.12	0.44	0.07	2.8	1.1	4.2	0.6	0.05	0.03	0.08	0.01	97.2	86.5	100.0	1.9
32		9:05 AM	9:40 AM			22	21	68	0-2	95.80	96.89	84.78	99.13	2.92	0.07	0.05	0.11	0.01	1.6	1.2	2.3	0.2	0.02	0.01	0.03	0.00	97.0	88.6	100.0	1.3
33		9:50 AM	10:24 AM			19	22	65	0-2	97.77	98.57	89.12	99.98	2.00	0.50	0.06	1.18	0.27	2.0	1.1	3.0	0.5	0.03	0.01	0.06	0.01	95.7	72.1	100.0	2.1
34		10:51 AM	11:06 AM			25	22	65	2-4	98.36	99.07	97.46	99.29	0.30	0.19	0.09	0.48	0.06	2.0	0.9	2.7	0.4	0.03	0.02	0.05	0.01	95.3	82.9	100.0	2.4
35		11:10 AM	11:25 AM			25	22	65	2-4	98.47	99.16	94.52	99.49	0.70	0.25	0.05	0.79	0.15	0.2	0.1	0.7	0.1	0.00	0.00	0.00	0.00	75.2	31.1	100.0	11.1
36		11:52 AM	12:07 PM			45	24	61	0-2	98.46	99.15	92.84	99.64	0.62	0.10	0.03	0.49	0.06	3.2	0.4	6.4	1.3	0.03	0.00	0.07	0.02	85.0	0.1	100.0	15.8
37		12:22 PM	12:37 PM			15	33	40	0-2	98.16	98.89	96.34	99.73	0.69	1.63	0.69	4.72	0.54	0.5	0.1	0.8	0.2	0.01	0.00	0.02	0.00	89.0	4.6	100.0	8.3
38		1:10 PM	1:27 PM			29	33	41	0-2	98.24	98.96	95.03	99.99	0.54	0.45	0.11	1.36	0.22	2.1	1.0	3.1	0.3	0.03	0.01	0.05	0.01	88.4	44.9	100.0	6.1
39		1:29 PM	1:43 PM		L	34	33	41	0-2	96.24	97.27	89.45	99.84	1.29	0.91	0.07	1.65	0.28	0.3	0.0	1.0	0.2	0.00	0.00	0.01	0.00	51.5	0.1	100.0	29.2

Table 2: Complete Mantis Results.

Appendix B: Validation of the VISR method

Precision and Accuracy of the VISR Method for Flare Monitoring

Extended Abstract: ME92
Presented at the conference:
Air Quality Measurement Methods and Technology
April 2-4, 2019
Durham, NC

Jon Morris, Yousheng Zeng, and Srikanth Mutyala
Providence Photonics, Baton Rouge, Louisiana

Introduction

Industrial flares represent a large category of air emission sources for Volatile Organic Compounds (VOC), air toxics, and greenhouse gases (GHG)[1-4]. Depending on their combustion efficiency (CE), the emissions of these air pollutants can be significantly different. Despite the large contribution of flares to air emission inventories, flares are the only source category for which no EPA test or monitoring methods can be applied to directly measure their efficiency or emission rates. As a result, flare emissions in air emission inventories may carry significant uncertainties.

A method based on Video Imaging Spectral Radiometry (VISR) has been developed for testing or continuously monitoring combustion efficiency (CE) of industrial flares[5]. To validate the VISR method, tests were conducted at flare test facilities of Zeeco, Inc. (Zeeco) and John Zink Hamworthy Combustion (John Zink), both located in Tulsa, Oklahoma, in September and October 2016, respectively. The test at Zeeco included both an air assisted flare and a steam assisted flare. Twenty-eight flare conditions were tested, 14 for the air flare and 14 for the steam flare. This test is referred to as the "Zeeco Test" in this paper.

The test at John Zink was part of a program sponsored and organized by the Petroleum Environmental Research Forum (PERF), an industry consortium. PERF project 2014-10 Direct Monitoring of Flare Combustion Efficiency was created and funded by participating PERF companies to provide a test platform for various developers/vendors of flare remote sensing technologies (Invitees) to participate in a blind test to evaluate the effectiveness of each technology. The blind test was administered by John Zink. Testing began on October 17th, 2016 and continued for 10 days, concluding on October 27th, 2016. The flare tip used was the John Zink model EEF-QSC-36, which was the same flare tip used during the 2010 TCEQ Flare Study[4]. A test protocol was developed which identified a series of test conditions to evaluate various factors that could affect flare CE measurement. Only limited logistical and environmental factors were shared with the Invitees (i.e., distance from the flare, view angle with respect to flame orientation due to wind, sun in/out of the field of view, daytime/nighttime testing). Information regarding flare operations such as the type of fuel gas used, firing rates, steam rates or any other flare operating parameters was concealed from Invitees. A total of 45 test points was evaluated over the 10 days of testing. Extractive sampling was performed on each test point as the control method for flare CE measurement. The results of the extractive sampling were not provided to Invitees until Invitees submitted their won results based on their respective measurement technology. This test is referred to as the "PERF Test" in this paper.

In this paper, the precision and accuracy of the VISR method are evaluated based on the test campaigns described above.

Methods and experimental setup

The VISR flare monitor is a remote monitoring device that can be positioned at any distance as long as the flare to be monitored is in the line of sight and there are a sufficient number of pixels of the flare flame image in the VISR monitor. The distances from flare to the VISR monitor in the experiments reported here were in the range of 174 feet to 650 feet. To evaluate the performance of the VISR method, an extractive sampling system was used as a reference method. A sample extraction apparatus was suspended by a crane over the flare plume to extract combustion product gases. The sample was transported through a heated sampling line to a sample manifold in a testing trailer. The sample manifold was connected to analyzers for oxygen (O_2), carbon dioxide (CO_2), carbon monoxide (CO), and hydrocarbon (HC). The methods for measuring O_2, CO_2, CO, and HC were EPA Method 3A, 3A, 10, and 25A, respectively. The level of O_2 was used to confirm that the sampling probe was in the flare plume. The concentrations of CO_2, CO, and HC were used to calculate flare CE per method used in the 2010 TCEQ flare study[3].

These test campaigns covered a wide range of process conditions: two steam flares and one air flare; multiple vent gas compositions (natural gas, propane, propylene, hydrogen, in pure form or mixed with nitrogen; vent gas flow range from 10 lb/hr to 10,000 lb/hr; various steam and air assist levels resulting in combustion zone net heating value (NHVcz) in a range of 120 to 1,250 Btu/scf for the steam flares and net heating value dilution parameter (NHVdil) in a range of 6.7 to 244 Btu/ft^2 for the air flare.

The test campaigns also covered a wide range of environmental conditions: distance ranging from 174 ft. to 650 ft.; different wind speed and direction (crosswind, wind oriented towards VISR device, and wind oriented away from VISR device); daytime vs. nighttime; various sky conditions (blue sky, cloudy, moving clouds); the Sun in or out of field of view; rain, and fog.

Results and Discussions

Precision

Precision is a measure of how the results of multiple measurements by the same method scatter while the target of the measurement holds steady. This is difficult to assess for flare measurements because even when the flare operating conditions are held steady (as they were in each test point of the PERF Test), the flare CE may change due to changes in environmental conditions. Analyte spiking or quadruplet sampling described in EPA Method 301 would help to isolate the measurement method precision from the fluctuation of the target itself[6]. However, these methods are not feasible for flare measurement. Nevertheless, the measurement precision can still be evaluated using the data from the PERF test. For each PERF test condition, 4 segments of measurement were made by the extractive method and 3 segments of measurement were made by VISR while the flare operating conditions were held constant (although flare CE did fluctuate due to changes in environmental conditions). The standard deviation (SD) and relative standard deviation (RSD) can be calculated based on these replicate measurements. **Table 1** is a summary of the SD and RSD for both the VISR method and the extractive method used in the PERF Test. As shown in **Table 1**, the RSD for the VISR method is in a range of 0.07% to 1.98% with an average of 0.62%. The variation of the VISR method appears to be slightly better than the extractive method from the perspective of both the average and the range of the RSD values, suggesting that the precision of VISR is at least as good as the extractive method. Note that in both cases, the variation due to changing environmental conditions is included in the RSD as there is no practical method to separate it. Despite the inclusion of environmental changes, the RSD is more than an order of magnitude smaller than 20% as required in EPA Method 301 (Section 9.0)[6]. If a more stringent criteria is used in which the 20% limit on RSD is applied to the most relevant range of 90-100 % CE measurement (i.e., in the span of 10 % CE measurement), the criteria would be SD < 2 % CE (20% of 10% = 2 % CE). As shown in **Table 1**, the highest SD is 1.84 measured as % CE, which is lower than the SD of 2 % CE measurement and therefore satisfies the more stringent criteria.

Table 1. Relative Standard Deviation (RSD) of VISR and extractive method per PERF Test

Method	CE Avg.	CE Range	SD Avg.	SD Range	RSD Avg.	RSD Range
VISR	96.47	80.61-99.91	0.59	0.07-1.84	0.62%	0.07-1.98%
Extractive	96.41	83.50-100.00	0.83	0.00-2.61	0.88%	0.00-2.72%

The Zeeco Test did not include multiple replicated measurements under each test condition. Therefore, a precision analysis is not performed on that data.

Accuracy

The accuracy of the VISR method is evaluated based on the Zeeco Test and PERF Test. In these two tests, the flare CE was measured by both the VISR method and the extractive method. The extractive method was used as the control (reference) method. Strictly speaking, what can be assessed is the agreement between the two methods, not the accuracy of either method because the true flare CE is unknown. The agreement between the two methods can be evaluated using a statistical method. One such method is to use t-test on the differences between the paired CE measurements by VISR and extractive methods. This method is the same as the method used in EPA Method 301 to determine if there is a difference caused by different sample storage time[6] (it should be noted that the methods for bias described in Method 301 are not directly applicable because they are specifically designed for analyte/isotopic spiking or quadruplet sampling systems, which are not feasible for flare measurement). The value of the t-statistic is calculated using the following equation.

$$t = \frac{|d_m|}{\frac{SD_d}{\sqrt{n}}}$$

Where d_m and SD_d are the mean and the standard deviation of the difference of the paired samples (VISR and extractive sample), and n is the total number of samples. The resulted t-statistic value is compared to the critical value of the t-statistic with a 95 percent confidence level and n-1 degree of freedom. If the resulted t-statistic value is less than the critical value, the difference between the VISR method and the extractive method is not statistically significant, i.e., the two methods are statistically the same. The results of the t-statistical analysis for both Zeeco and PERF tests are summarized in **Table 2**. The number of samples (tests) in **Table 2** is less than the number of tests actually conducted because some tests were designed for other purposes (e.g., smoke test) and they are not included in the evaluation of the agreement between VISR and extractive methods.

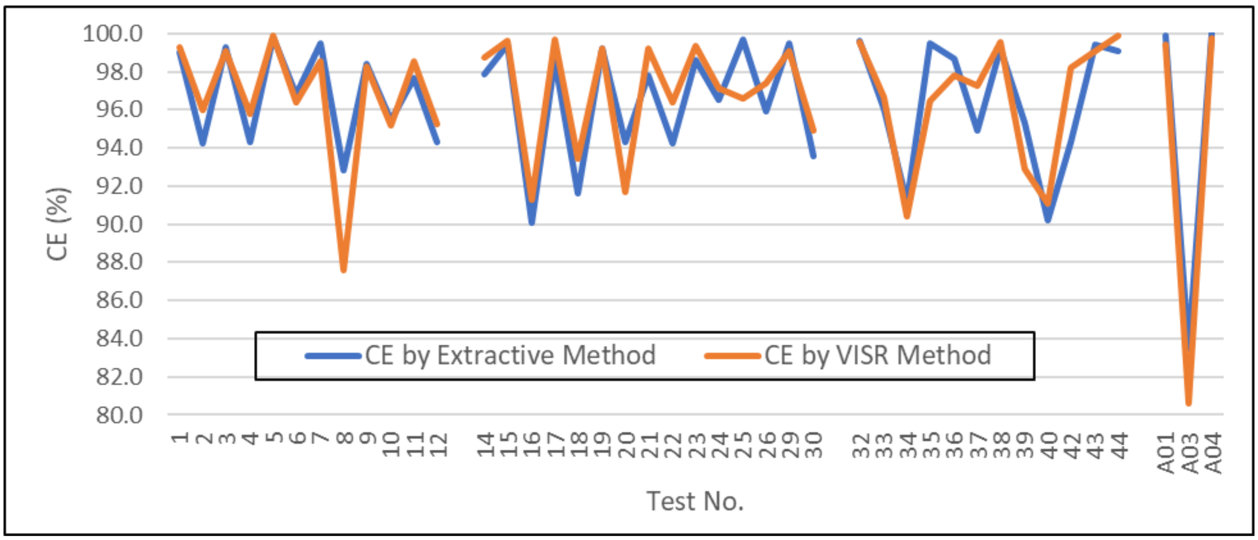
Table 2. t-Test to determine if the VISR method is different from the extractive method

	Zeeco Test (Steam Flare)	**Zeeco Test (Air Flare)**	**PERF Test**
No. of Samples, n	11	9	42
Mean Difference, d_m (% CE)	0.30	-0.21	0.07

Standard Deviation, SD_d (% CE)	1.32	0.65	1.69
t-Statistic Value	0.756	0.967	0.254
Degree of Freedom	10	8	41
t_95 Critical Value	2.228	2.306	2.020
Statistically Different?	No	No	No

As demonstrated in **Table 2**, statistically there is no difference between the flare CE measured by the VISR method and by the extractive method. The agreement between the two measurement methods can also be illustrated in **Figure 1** using the results from the PERF Test.

Figure 1. Flare CE measured by VISR method and extractive method – PERF Test results



Conclusion

Industrial flares can now be measured or continuously monitored by the VISR method for their performance, i.e., combustion efficiency (CE). The VISR method is a remote sensing method and can be deployed easily and practically. The VISR method transforms flare testing/monitoring from most difficult task (impossible in many cases) to a task that is easier than most conventional air emission testing methods. With the significant potential benefits that the VISR method can bring, it is important to characterize and understand the precision and accuracy of this method.

Through a large number of tests under various process and environmental conditions, a high precision and accuracy have been demonstrated for the VISR method. The relative standard deviation (RSD) is in the range of 0.07-1.98% with an average RSD of 0.62% for flare CE in the range from 80 to 100%. The average RSD of 0.62% is more than an order of magnitude smaller than the minimum precision target of 20% RSD set in EPA Method 301. The highest SD is only 1.84 measured as % CE.

The flare CE measured by the VISR method is in excellent agreement with the flare CE measured by the extractive method. The mean difference between the two methods is in the range of -0.21 to 0.30 measured in % CE. The t-statistic value in each of the three test groups are well below its corresponding t-test critical value, passing the t-test with a substantial margin. Keep in mind that the extractive method is suitable only in research. It is virtually impossible to deploy the extractive method to elevated flares at industrial production facilities. Having a method that can be easily deployed to industrial sites and produce highly time-resolved and accurate flare measurement results is a significant advancement.

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Appendix C: Combustion Efficiency Versus Destruction Efficiency

With respect to emissions calculations or GHG reporting, it is important to consider the difference between combustion efficiency (CE) and destruction efficiency (DE). The VISR method measures CE, which is a measure of the efficiency of the flame to convert hydrocarbons into carbon dioxide and water. If the combustion efficiency is 100%, then all of the hydrocarbons have been oxidized all the way to carbon dioxide, leaving no hydrocarbons in the post combustion plume. CE will be reduced as the percentage of hydrocarbon in the post combustion plume increases. Destruction efficiency is a measure of the percentage of a compound that is destroyed (IE converted into another form), but not necessarily oxidized to the ultimate combustion product of carbon dioxide and water. In this case, it represents the percentage of hydrocarbons destroyed. The hydrocarbons could be converted to carbon dioxide, carbon monoxide, soot or another compound. As a result, DE is typically higher than CE. For emission inventory purposes, flares are generally deemed to have a DE of 98%, meaning 98% of the hydrocarbons sent to the flare are converted into another form. There is no quantitative method to convert the VISR CE data to DE, however we do have some points of reference. The US EPA Refinery Sector Rule (40 CFR 63.670 (r) equates a CE of 96.5% to a DE of 98%. The rule references the John Zink combustion handbook (Baukal, 2001).

In addition, there have been two major studies which have measured both CE and DE with extractive sampling: the 2010 TCEQ Study and the 2016 PERF Study. Both of these studies were conducted at John Zink's research facility in Tulsa, Oklahoma. Taken collectively, these studies provide 71 individual measurements of CE and DE. *Figure 8* below shows the relationship between CE and DE from these two studies.

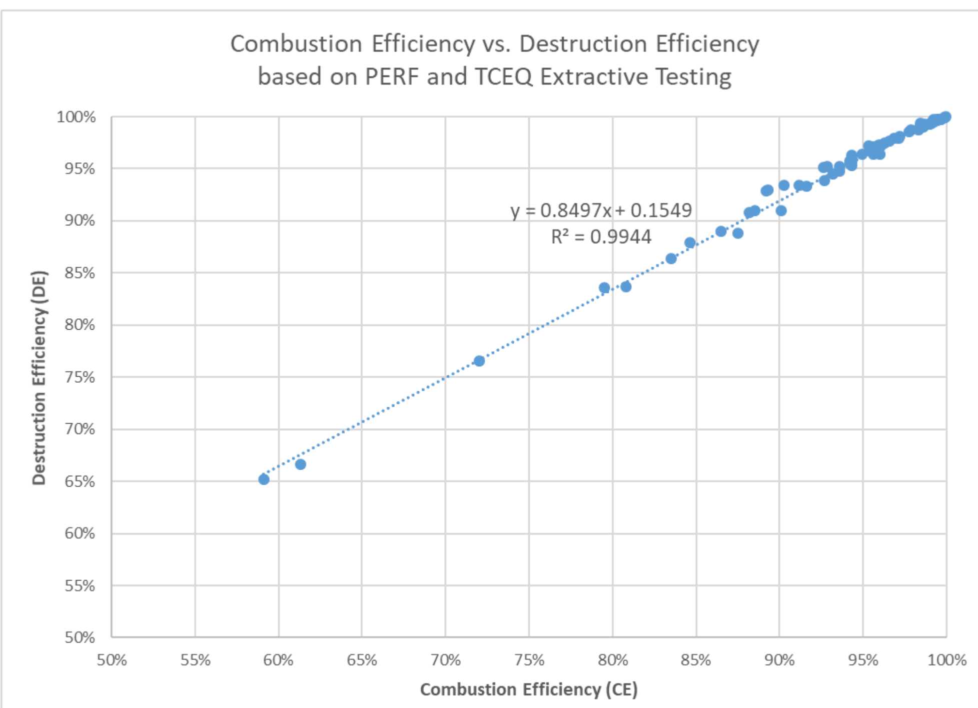

Figure 17. CE vs DE from extractive sampling during PERF and VISR studies.

As demonstrated by the chart, the relationship between DE and CE is quite linear. The fit equation to this data has an R^2 of 0.99. Equation 2 below can be used to convert CE to DE using this correlation:

$$DE\ (\%) = CE\ (\%) * 0.8497 + 0.1549$$

Equation 2

It should be noted that when SI is high and CE appears to be low, the destruction efficiency (DE) may still be high as the hydrocarbons are combusted into soot instead of oxidizing to the ultimate combustion products of water and CO_2. The CE-DE relationship shown in *Figure 8* is established under no smoke conditions. There has not been sufficient study on a similar CE-DE relationship when there is significant smoke in the flare. This equation will be valid for CE within a range of 60% to 99.4%. Above 99.4%, the DE will be capped at 100%. Below 60%, there is no extractive data available to extend the correlation.

PROVIDENCE PHOTONICS

[redacted]

VISR Field Study

Final Report | Revision 1.0

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[redacted]

NORTH DAKOTA

PREPARED BY
Providence Photonics, LLC | 1201 Main Street, Baton Rouge, LA 70802

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Introduction

Providence Photonics, LLC (Providence) has developed a method to remotely measure the performance of an industrial flare using Video Imaging Spectral Radiometry (VISR). The VISR method provides five flare performance metrics: combustion efficiency (CE), smoke index (SI), flame stability (FS), flame footprint (FF), and fractional heat release (FH).

Providence conducted a field campaign using VISR at various [redacted] facilities in North Dakota from April 4th, 2022 to April 8th, 2022. A total of 92 individual flare measurements were performed. In addition to the VISR measurements, an mp4 video was captured for each flare using a FLIR GF320 optical gas imaging camera. This report summarizes the data and findings from the campaign.

Background

The VISR method utilizes a multi-spectral midwave infrared imager to measure relative concentrations of combustion gases. The method was designed to be a continuous and autonomous remote flare monitor, but in this study it was deployed as a mobile technology for a short-term measurement. ***Figure 1*** below shows the VISR device deployed at a [redacted] facility in North Dakota. The VISR device and related equipment was powered from the 12V battery system of the vehicle.

Figure 1: VISR device deployed at a [redacted] facility in North Dakota.

Results

The results from VISR measurements are tabulated in **Appendix A** and a summary is provided in *Table 1 below*.

Table 1: Summary VISR Results.

ID	Site Description	Flare Description	Distance (m)	Temp (°C)	RH (%)	Avg Wind Speed (mph)	FLIR Video	CE Avg (%)	DRE Avg (%)	SI Avg	FF Avg (m2)	FH Avg (MMBT	FS Avg (%)
1	[redacted]	High Pressure	46	3	72	4 to 6	MOV_2332.mp4	98.12	98.86	1.0	0.4	0.004	89.1
2		Low Pressure	54	3	72	4 to 6	MOV_2334.mp4	99.68	99.94	0.3	0.3	0.004	96.8
3		High Pressure	38	9	53	4 to 6	MOV_2337.mp4	99.50	99.93	0.8	1.4	0.021	95.5
4		Low Pressure	46	9	53	4 to 6	MOV_2338.mp4	99.05	99.63	0.7	1.4	0.025	96.6
5		High Pressure	44	8	59	8 to 10	MOV_2339.mp4	99.76	99.95	0.2	3.4	0.051	96.2
6		Low Pressure	61	8	59	8 to 10	MOV_2340.mp4	99.35	99.83	0.6	0.5	0.004	93.7
7		High Pressure	45	10	53	4 to 6	MOV_2341.mp4	99.54	99.92	0.5	0.6	0.007	81.8
8		High Pressure	42	11	50	6 to 8	MOV_2342.mp4	99.03	99.61	0.4	1.8	0.028	93.6
9		Low Pressure	53	11	50	6 to 8	MOV_2344.mp4	99.36	99.86	0.4	0.9	0.011	91.0
10		Low Pressure	44	14	39	12 to 14	MOV_2348.mp4	98.90	99.52	0.6	0.7	0.010	93.4
11		HP/LP Assisted	49	14	38	14 to 16	MOV_2351.mp4	97.66	98.47	0.2	5.5	0.088	97.4
12		High Pressure South	49	14	38	14 to 16	MOV_2354.mp4	98.59	99.23	1.5	3.4	0.092	92.5
13		Low Pressure South	52	14	38	14 to 16	MOV_2356.mp4	99.46	99.89	0.7	0.1	0.001	92.1
14		High Pressure North	38	14	38	14 to 16	MOV_2358.mp4	98.88	99.50	0.1	0.3	0.003	92.6
15		Low Pressure North	32	14	38	14 to 16	MOV_2359.mp4	99.49	99.85	0.3	0.1	0.001	89.4
16		High Pressure	37	18	32	10 to 12	MOV_2362.mp4	98.04	98.79	0.4	1.2	0.020	89.9
17		Low Pressure	45	18	32	10 to 12	MOV_2363.mp4	98.59	99.26	0.7	0.1	0.001	94.5
18		High Pressure	34	19	32	12 to 14	MOV_2365.mp4	98.90	99.51	0.6	0.2	0.002	95.2
19		Low Pressure	38	19	32	12 to 14	MOV_2366.mp4	98.46	99.15	0.1	0.5	0.007	93.3
20		High Pressure	37	19	30	8 to 10	MOV_2367.mp4	98.68	99.34	0.2	3.2	0.056	96.7
21		Low Pressure	45	19	30	8 to 10	MOV_2368.mp4	99.46	99.87	0.7	0.2	0.002	94.9
22		Dual HP/LP	44	6	55	8 to 10	MOV_2369.mp4	99.57	99.91	0.4	0.9	0.025	87.8
23		Low Pressure	68	6	55	12 to 14	MOV_2371.mp4	99.48	99.92	0.1	1.3	0.020	95.9
24		Dual HP/LP	43	7	49	14 to 16	MOV_2374.mp4	98.83	99.45	0.6	0.2	0.001	90.8
25		Dual HP/LP	48	8	42	8 to 10	MOV_2375.mp4	99.24	99.77	1.0	0.3	0.002	91.5
26		Low Pressure	46	7	44	14 to 16	MOV_2380.mp4	98.80	99.36	0.2	0.4	0.004	77.4
27		Dual HP/LP	42	7	42	18 to 20	MOV_2385.mp4	88.30	90.52	0.3	5.8	0.100	95.2
28		Dual HP/LP	42	8	43	18 to 20	MOV_2390.mp4	93.40	94.85	0.1	1.7	0.021	82.9
29		Low Pressure	46	8	44	18 to 20	MOV_2392.mp4	99.66	99.94	0.2	0.8	0.009	91.1
30		Dual HP/LP	37	10	41	16 to 18	MOV_2396.mp4	98.43	99.11	0.4	0.5	0.005	85.6
31		Low Pressure	43	10	41	22 to 24	MOV_2397.mp4	99.38	99.87	1.5	6.3	0.130	93.0
32		High Pressure	48	9	42	18 to 20	MOV_2398.mp4	99.67	99.95	0.3	1.0	0.013	89.8
33		Dual HP/LP	43	8	48	18 to 20	MOV_2400.mp4	96.17	97.20	0.2	5.5	0.088	95.7
34		Dual HP/LP	49	7	63	10 to 12	MOV_2401.mp4	99.88	99.95	0.2	12.4	0.257	97.2
35		High Pressure	50	7	68	4 to 6	MOV_2402.mp4	99.31	99.80	0.6	0.7	0.009	85.9
36		Low Pressure	40	7	68	4 to 6	MOV_2403.mp4	99.66	99.95	0.5	0.9	0.012	94.5
37		High Pressure	32	9	61	8 to 10	MOV_2404.mp4	99.52	99.91	0.8	0.2	0.003	92.7
38		Low Pressure	37	9	61	8 to 10	MOV_2405.mp4	99.40	99.89	0.5	0.6	0.007	96.2
39		Dual HP/LP	55	7	68	6 to 8	MOV_2406.mp4	99.23	99.78	0.2	1.0	0.010	85.7
40		High Pressure	52	6	67	8 to 10	MOV_2407.mp4	98.35	99.06	1.6	3.1	0.072	94.4
41		Low Pressure	60	6	67	8 to 10	MOV_2408.mp4	99.56	99.88	0.3	0.5	0.005	89.4
42		Dual HP/LP	68	2	79	10 to 12	MOV_2410.mp4	98.51	99.13	0.6	0.9	0.018	90.3
43		High Pressure	37	1	78	12 to 14	MOV_2411.mp4	99.26	99.71	0.4	0.8	0.009	88.9
44		Low Pressure	60	1	78	12 to 14	MOV_2412.mp4	97.88	98.66	0.1	1.1	0.011	94.7
45		Low Pressure	48	3	75	10 to 12	MOV_2413.mp4	98.87	99.48	0.9	0.3	0.004	95.9
46		Dual HP/LP	58	3	73	16 to 18	MOV_2416.mp4	98.66	99.31	0.5	9.0	0.181	97.7
47		Dual HP/LP	46	9	57	16 to 18	MOV_2418.mp4	97.12	97.96	0.8	0.6	0.008	86.5
48		Dual HP/LP	75	9	48	10 to 12	MOV_2419.mp4	97.37	98.22	0.2	7.2	0.134	89.1
49		Dual HP/LP	37	11	49	18 to 20	MOV_2420.mp4	98.55	99.23	1.2	0.3	0.003	86.4
50		High Pressure	40	7	43	12 to 14	MOV_2422.mp4	99.10	99.68	0.1	6.6	0.131	97.0
51		Dual HP/LP	43	12	43	30 to 32	MOV_2423.mp4	99.18	99.74	2.0	0.1	0.001	96.2
52		Low Pressure	50	8	29	26 to 28	MOV_2424.mp4	99.41	99.83	0.8	0.2	0.002	92.3
53		High Pressure	36	8	29	26 to 28	MOV_2425.mp4	99.27	99.80	0.1	0.1	0.000	82.3
54		Dual HP/LP	58	-1	68	10 to 12	MOV_2426.mp4	98.75	99.40	0.3	1.6	0.020	90.8
55		Dual HP /LP	49	-1	67	18 to 20	MOV_2427.mp4	98.43	99.10	0.6	1.6	0.037	86.2
56		Low Pressure	28	-2	72	14 to 16	MOV_2428.mp4	99.10	99.67	0.1	0.7	0.010	94.2
57		Dual HP/LP	61	-1	79	18 to 20	MOV_2429.mp4	97.10	98.00	0.2	2.2	0.031	80.9
58		Dual HP/LP	53	2	70	12 to 14	MOV_2430.mp4	99.13	99.63	0.4	1.3	0.018	85.9
59		Low Pressure	40	5	54	20 to 22	MOV_2432.mp4	99.08	99.67	0.2	0.9	0.013	92.3
60		Dual HP/ LP	70	5	50	16 to 18	MOV_2433.mp4	96.31	97.31	0.4	6.5	0.118	74.6
61		Dual HP/LP	42	3	51	18 to 20	MOV_2434.mp4	99.57	99.91	0.5	0.2	0.002	81.3
62		Low Pressure North	37	5	45	18 to 20	MOV_2435.mp4	99.00	99.55	0.5	0.7	0.010	91.5
63		Low Pressure South	43	5	45	18 to 20	MOV_2437.mp4	99.36	99.79	0.6	0.2	0.001	84.6
64		High Pressure	41	5	45	18 to 20	MOV_2438.mp4	99.03	99.56	3.0	0.6	0.009	95.0
65		High Pressure North	34	6	38	22 to 24	MOV_2439.mp4	99.68	99.94	0.3	0.9	0.014	90.6
66		High Pressure South	48	6	38	22 to 24	MOV_2440.mp4	99.75	99.95	0.6	0.9	0.014	89.8
67		Low Pressure	58	6	38	22 to 24	MOV_2441.mp4	99.19	99.71	0.2	0.2	0.002	84.2
68		Low Pressure	31	6	41	20 to 22	MOV_2442.mp4	99.64	99.94	0.4	1.3	0.028	93.4
69		High Pressure	32	9	34	10 to 12	MOV_2443.mp4	98.80	99.42	0.4	0.7	0.009	91.7
70		Low Pressure	39	9	34	10 to 12	MOV_2444.mp4	99.27	99.80	0.3	0.6	0.008	87.8
71		Low Pressure	37	7	37	16 to 18	MOV_2445.mp4	98.57	99.23	0.6	0.3	0.003	87.7
72		Dual HP/LP	68	8	36	20 to 22	MOV_2446.mp4	98.48	99.14	0.3	7.0	0.137	87.9
73		Dual HP/LP	58	11	32	6 to 8	MOV_2451.mp4	98.02	98.78	0.3	1.2	0.013	80.3
74		Dual HP/LP	91	7	42	16 to 18	MOV_2452.mp4	98.73	99.34	1.2	22.6	0.842	96.8
75		Low Pressure	39	-2	66	0 to 2	MOV_2453.mp4	98.29	99.01	1.0	0.7	0.012	95.8
76		High Pressure	30	-2	66	0 to 2	MOV_2454.mp4	99.43	99.87	0.7	0.3	0.004	94.9
77		Dual HP/ LP	76	2	55	0 to 2	MOV_2455.mp4	96.73	97.58	0.6	30.0	0.288	94.1
78		Dual HP/LP	83	3	59	0 to 2	MOV_2459.mp4	95.02	96.23	0.2	6.1	0.100	87.1
79		Dual HP/ LP	57	8	42	0 to 2	MOV_2460.mp4	99.74	99.95	1.1	0.2	0.001	95.3
80		Dual HP/LP	112	10	29	0 to 2	MOV_2461.mp4	99.44	99.90	0.5	53.6	1.098	96.8
81		Dual HP/LP	112	10	29	0 to 2	MOV_2462.mp4	99.36	99.82	0.5	61.2	1.239	96.5
82		Dual HP/LP	167	12	25	6 to 8	MOV_2463.mp4	99.20	99.72	0.7	53.8	1.104	96.9
83		Low Pressure	50	11	26	4 to 6	MOV_2464.mp4	96.50	97.49	0.1	1.6	0.025	88.8
84		Low Pressure South	37	13	25	4 to 6	MOV_2466.mp4	99.60	99.91	0.3	0.6	0.008	95.1
85		Low Pressure North	36	13	25	4 to 6	MOV_2467.mp4	99.18	99.69	0.5	0.4	0.005	93.7
86		Low Pressure South	20	13	25	4 to 6	MOV_2468.mp4	99.52	99.91	0.2	0.1	0.001	94.9
87		Low Pressure	59	14	23	4 to 6	MOV_2469.mp4	99.78	99.94	0.8	0.5	0.004	92.4
88		Low Pressure	40	14	23	4 to 6	MOV_2470.mp4	99.70	99.95	0.9	0.4	0.003	96.5
89		High Pressure	50	13	21	2 to 4	MOV_2471.mp4	99.21	99.69	1.0	9.4	0.265	94.9
90		High Pressure	63	13	21	2 to 4	MOV_2472.mp4	99.21	99.76	0.2	1.1	0.009	90.4
91		Dual HP/LP	42	15	18	2 to 4	MOV_2474.mp4	98.90	99.52	0.2	2.0	0.034	96.6
92		Low Pressure	30	12	17	8 to 10	MOV_2475.mp4	99.14	99.72	0.6	0.4	0.004	87.2

Flare Performance Metrics

VISR provides five flare performance metrics at a 1-second data interval:

1. COMBUSTION EFFICIENCY (0 TO 100%): Combustion efficiency (CE) is a measure of the relative concentration of hydrocarbon vs. carbon dioxide in the post combustion gas plume. If there is no hydrocarbon present in the post combustion gas plume, then CE is 100%. CE should not be confused with Destruction and Removal Efficiency (DRE). The difference between these two metrics is discussed in **Appendix C**. While CE is directly measured by the VISR method, DRE is derived using correlations established through extractive sampling as discussed in **Appendix C**.
2. SMOKE INDEX (0 TO 10): Smoke index (SI) is a unit-less number which indicates the degree of visible emissions within the combustion envelope. A SI of 0 means no visible emissions are present while a SI of 10 means the flare has heavy black smoke. While SI only represents the degree of visible emissions within the combustion envelope, it is generally correlated to opacity and a SI above 2 indicates that some visible emissions are likely present outside of the combustion envelope.
3. FLAME FOOTPRINT (FT^2): Flame footprint (FF) is a measure of the flame size in square feet. It is not necessarily correlated to the visible flame size as the FF is determined by the radiance, not the visible flame. Note that the orientation of the flame will impact the FF as the depth of the flame will change with viewing angle.
4. FRACTIONAL HEAT RELEASE (BTU/HR): Fractional Heat Release (FH) is a measure of the heat released from flare combustion in the spectral bands monitored by the VISR imager. Although it is not a measure of the total heat release across the entire energy spectrum, FH is expected to be correlated to the total heat release.
5. FLAME STABILITY (0 TO 100%): Flame stability (FS) is a measure of the change in radiance measured by the VISR imager in a 1-second interval. A FS of 100% indicates a flame that has a constant radiance. A low FS value (generally lower than 80%) indicates a flame with significant radiance fluctuation within 1 second interval, suggesting a less stable flame. Variability on a longer time scale will not be described by the flame stability metric.

Data Quality Indicators

The VISR method has two important data quality indicators (DQI) to assess the quality of the measurement. The first is the number of pixels in the flame combustion envelope. The VISR method requires at least 30 pixels to accurately determine the performance metrics of the flame. The VISR device has a fixed focal length, so the number of pixels in the flame is determined by the size of the flame and the distance from the VISR imager to the flame. For this study the flame size was above the minimum number of pixels for all measurements performed.

The second important DQI is the Smoke Index level. As the smoke index increases above 2.0 (this threshold may vary within a range of 1-2 depending on specific flares), visible emissions are generally present in the flame. When visible emissions become significant, the SI value will climb even higher to a maximum value of 10 for thick black smoke. Extractive testing shows that SI values above 3.0 may cause a small negative bias on the CE measurement (< 1%) and SI values above 5 may cause a significant negative bias to CE, as confirmed by testing with an extractive sampling method as a control. Any data points with a smoke index above 3 were removed from the summary tables and **Appendix A** results.

Observations

The following sections describe observations and comparisons derived from the dataset.

Distribution of Flare DRE

The majority of flares measured (90%) had a DRE greater than 98%, and 84% had a DRE greater than 99%. ***Figure 2*** shows the distribution of flare DRE measurements across the entire dataset.

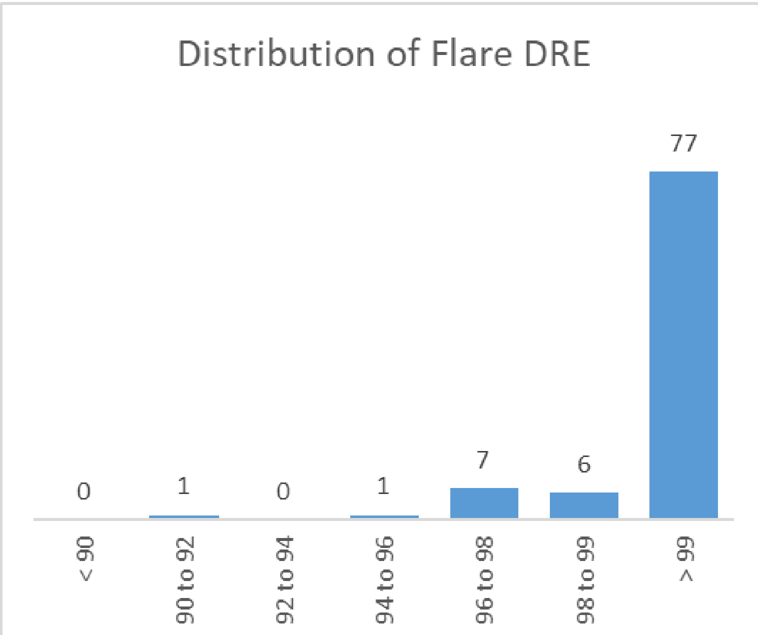

Figure 2: Distribution of Flare DRE measurements.

[redacted]

The lowest performing flare [redacted]

Figure 3 provides a time series plot of the Destruction Efficiency vs. Fractional Heat release (FH). The average DRE observed during this 15-minute measurement period was 90.82%.

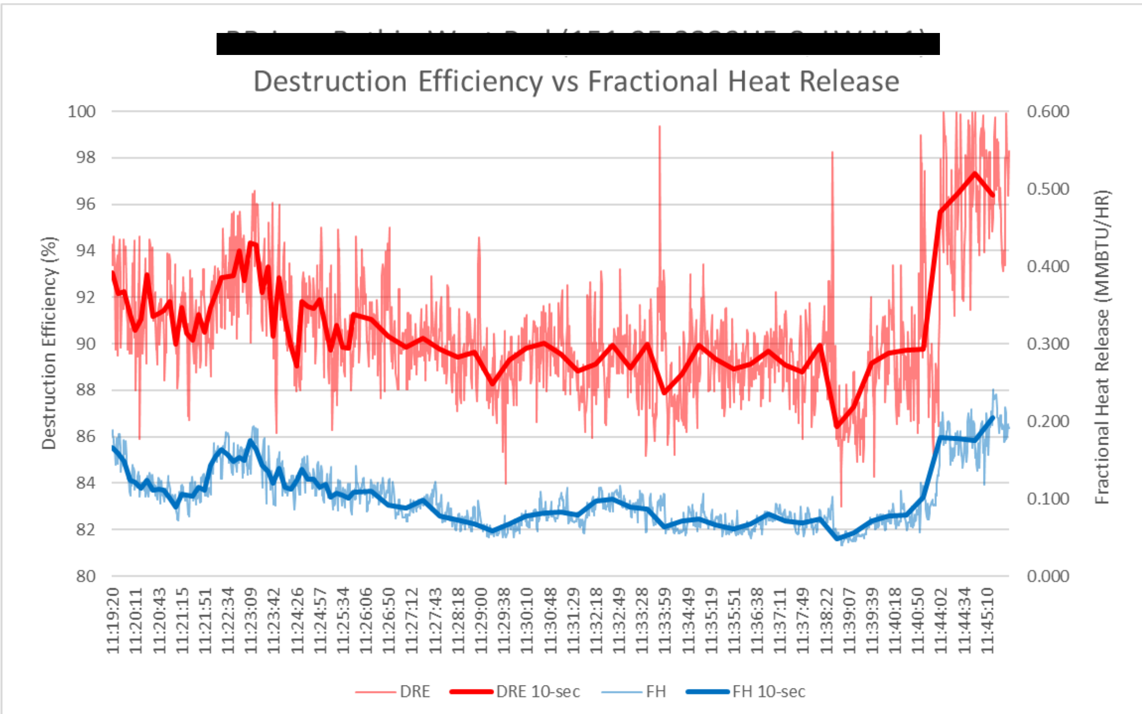

Figure 3: Destruction Efficiency vs. Fractional Heat Release for [redacted].

[redacted]

The flare with next lowest performance was the [redacted]). ***Figure 4*** provides a time series plot of the Destruction Efficiency vs. Fractional Heat release (FH). The average DRE observed during this 15-minute period was 94.85%.

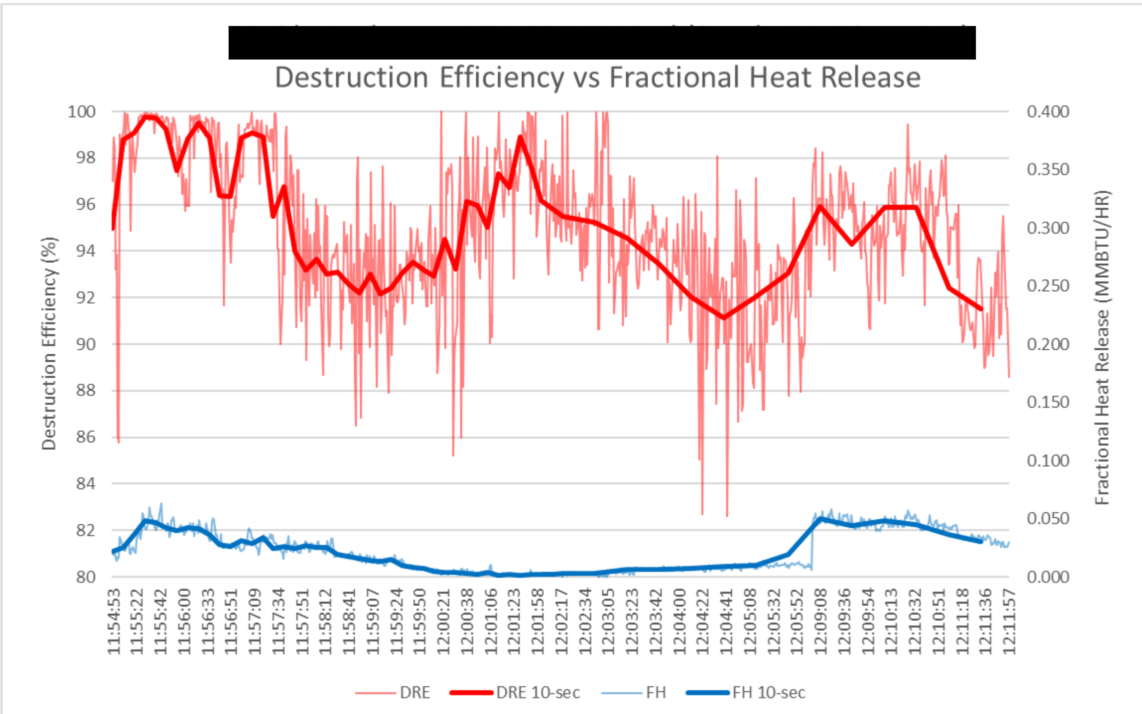

Figure 4: Destruction Efficiency vs. Fractional Heat Release for [redacted]

[redacted]

The flare with next lowest performance was the [redacted]-[redacted] ***Figure 5*** provides a time series plot of the Destruction Efficiency vs. Fractional Heat release (FH). The average DRE observed during this 15-minute period was 96.23%.

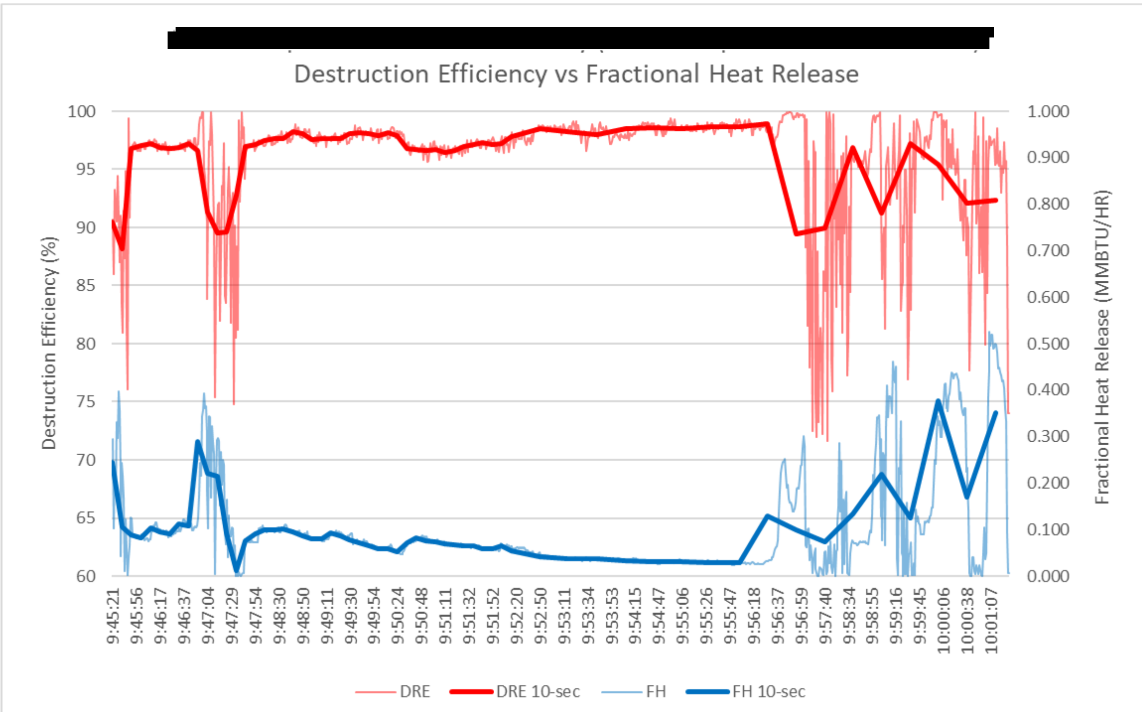

Figure 5: Destruction Efficiency vs. Fractional Heat Release and Smoke Index for [redacted]

Summary

In total, 92 flares across 67 sites were measured during the five-day study. The average DRE for all flares measured was 99.3%. Although there were a handful of flares with a DRE less than 98% (9 of 92), the majority of flares measured had a DRE which exceeded 99% (77 of 92). This data is consistent with prior studies in the area.

References

1. Yousheng Zeng, Jon Morris & Mark Dombrowski (2015) Validation of a new method for measuring and continuously monitoring the efficiency of industrial flares, Journal of the Air & Waste Management Association, 66:1, 76-86, DOI: 10.1080/10962247.2015.1114045

Appendix A: Results

Date/Time				Description				Conditions					Efficiency (%)					Smoke Index (0-10)				Flare Footprint (m^2)				Fractional Heat (MMBTU/HR)				Flame Stability (%)			
ID	Date	Start Time (Local)	End Time (Local)	Site Description	Latitude	Longitude	Flare Description	Distance (m)	Temp (°C)	RH (%)	Avg Wind Speed (mph)	FLIR Video	CE Avg	DRE Avg	CE Min	CE Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD
1	4/4/2022	8:04 AM	8:20 AM				High Pressure	46	3	72	4 to 6	MOV_2332.mp4	98.12	98.86	94.65	99.82	0.83	1.0	0.4	1.9	0.2	0.4	0.3	0.6	0.0	0.004	0.002	0.007	0.001	89.1	64.3	99.9	5.5
2	4/4/2022	8:23 AM	8:39 AM				Low Pressure	54	3	72	4 to 6	MOV_2334.mp4	99.68	99.94	98.53	99.99	0.16	0.3	0.2	1.1	0.1	0.3	0.2	0.7	0.0	0.004	0.002	0.006	0.001	96.8	42.6	100.0	4.0
3	4/4/2022	8:55 AM	9:10 AM				High Pressure	38	9	53	4 to 6	MOV_2337.mp4	99.50	99.93	98.90	99.87	0.16	0.8	0.4	1.1	0.1	1.4	1.1	1.7	0.1	0.021	0.016	0.027	0.001	95.5	86.7	100.0	2.3
4	4/4/2022	9:11 AM	9:26 AM				Low Pressure	46	9	53	4 to 6	MOV_2338.mp4	99.05	99.63	95.73	99.70	0.47	0.7	0.3	1.2	0.2	1.4	1.1	1.8	0.1	0.025	0.021	0.034	0.002	96.6	88.3	100.0	1.8
5	4/4/2022	9:40 AM	9:55 AM				High Pressure	44	8	59	8 to 10	MOV_2339.mp4	99.76	99.95	98.41	99.89	0.07	0.2	0.1	0.4	0.0	3.4	2.5	4.4	0.3	0.051	0.035	0.067	0.004	96.2	88.8	100.0	1.8
6	4/4/2022	9:56 AM	10:12 AM				Low Pressure	61	8	59	8 to 10	MOV_2340.mp4	99.35	99.83	92.91	99.79	0.48	0.6	0.1	1.6	0.2	0.5	0.1	1.1	0.2	0.004	0.001	0.012	0.003	93.7	76.6	99.9	3.6
7	4/4/2022	10:25 AM	10:40 AM				High Pressure	45	10	53	4 to 6	MOV_2341.mp4	99.54	99.92	97.53	99.96	0.20	0.5	0.2	1.1	0.1	0.6	0.3	1.1	0.2	0.007	0.002	0.015	0.002	81.8	31.1	99.9	10.9
8	4/4/2022	11:06 AM	11:21 AM				High Pressure	42	11	50	6 to 8	MOV_2342.mp4	99.03	99.61	97.79	99.95	0.36	0.4	0.2	0.8	0.1	1.8	0.7	2.6	0.4	0.028	0.012	0.041	0.006	93.6	68.8	100.0	4.1
9	4/4/2022	11:23 AM	11:38 AM				Low Pressure	53	11	50	6 to 8	MOV_2344.mp4	99.36	99.86	98.34	99.84	0.24	0.4	0.1	1.5	0.2	0.9	0.3	1.6	0.2	0.011	0.004	0.022	0.004	91.0	69.9	100.0	5.4
10	4/4/2022	12:11 PM	12:26 PM				Low Pressure	44	14	39	12 to 14	MOV_2348.mp4	98.90	99.52	97.21	99.74	0.40	0.6	0.3	1.4	0.2	0.7	0.3	1.4	0.2	0.010	0.004	0.020	0.003	93.4	36.5	100.0	4.6
11	4/4/2022	12:44 PM	1:00 PM				HP/LP Assisted	49	14	38	14 to 16	MOV_2351.mp4	97.66	98.47	85.49	99.57	1.81	0.2	0.1	3.4	0.2	5.5	2.6	56.4	3.2	0.088	0.030	0.315	0.017	97.4	0.1	100.0	3.4
12	4/4/2022	1:15 PM	1:31 PM				High Pressure South	49	14	38	14 to 16	MOV_2354.mp4	98.59	99.23	84.95	99.99	1.29	1.5	0.4	3.2	0.5	3.4	0.6	11.7	1.9	0.092	0.012	0.242	0.063	92.5	21.1	100.0	5.7
13	4/4/2022	1:33 PM	1:48 PM				Low Pressure South	52	14	38	14 to 16	MOV_2356.mp4	99.46	99.89	98.42	99.96	0.24	0.7	0.3	1.3	0.1	0.1	0.1	0.3	0.0	0.001	0.001	0.002	0.000	92.1	30.6	100.0	4.5
14	4/4/2022	1:56 PM	2:11 PM				High Pressure North	38	14	38	14 to 16	MOV_2358.mp4	98.88	99.50	97.34	99.73	0.45	0.1	0.0	0.1	0.0	0.3	0.1	0.7	0.1	0.003	0.001	0.008	0.001	92.6	72.7	100.0	4.1
15	4/4/2022	2:12 PM	2:27 PM				Low Pressure North	32	14	38	14 to 16	MOV_2359.mp4	99.49	99.85	97.81	99.99	0.38	0.3	0.2	0.8	0.1	0.1	0.1	0.2	0.0	0.001	0.001	0.002	0.000	89.4	16.3	100.0	6.1
16	4/4/2022	2:41 PM	2:57 PM				High Pressure	37	18	32	10 to 12	MOV_2362.mp4	98.04	98.79	96.29	99.39	0.51	0.4	0.2	0.9	0.1	1.2	0.6	2.3	0.3	0.020	0.008	0.041	0.006	89.9	64.2	99.9	5.7
17	4/4/2022	2:57 PM	3:12 PM				Low Pressure	45	18	32	10 to 12	MOV_2363.mp4	98.59	99.26	96.80	99.70	0.46	0.7	0.2	2.2	0.4	0.1	0.1	0.3	0.0	0.001	0.000	0.003	0.001	94.5	77.3	100.0	3.2
18	4/4/2022	3:32 PM	3:47 PM				High Pressure	34	19	32	12 to 14	MOV_2365.mp4	98.90	99.51	96.36	99.85	0.46	0.6	0.4	1.0	0.1	0.2	0.1	0.3	0.0	0.002	0.001	0.002	0.000	95.2	84.9	99.9	2.3
19	4/4/2022	3:48 PM	4:07 PM				Low Pressure	38	19	32	12 to 14	MOV_2366.mp4	98.46	99.15	96.42	99.56	0.52	0.1	0.1	0.2	0.0	0.5	0.2	1.1	0.2	0.007	0.002	0.016	0.003	93.3	60.4	99.9	4.5
20	4/4/2022	4:22 PM	4:37 PM				High Pressure	37	19	30	8 to 10	MOV_2367.mp4	98.68	99.34	96.70	99.74	0.52	0.2	0.1	0.6	0.0	3.2	2.3	4.2	0.3	0.056	0.037	0.076	0.007	96.7	86.3	100.0	1.9
21	4/4/2022	4:38 PM	4:53 PM				Low Pressure	45	19	30	8 to 10	MOV_2368.mp4	99.46	99.87	98.40	99.94	0.28	0.7	0.3	1.6	0.3	0.2	0.1	0.5	0.1	0.002	0.000	0.006	0.002	94.9	84.1	100.0	2.4
22	4/5/2022	8:07 AM	8:22 AM				Dual HP/LP	44	6	55	8 to 10	MOV_2369.mp4	99.57	99.91	96.62	99.99	0.32	0.4	0.2	3.7	0.3	0.9	0.2	17.8	2.7	0.025	0.002	0.881	0.118	87.8	0.1	99.3	6.0
23	4/5/2022	9:04 AM	9:19 AM				Low Pressure	68	6	55	12 to 14	MOV_2371.mp4	99.48	99.92	98.59	99.87	0.17	0.1	0.1	0.2	0.0	1.3	0.8	1.8	0.2	0.020	0.013	0.025	0.002	95.9	55.8	100.0	3.2
24	4/5/2022	9:35 AM	9:50 AM				Dual HP/LP	43	7	49	14 to 16	MOV_2374.mp4	98.83	99.45	96.35	99.88	0.52	0.6	0.3	1.3	0.2	0.2	0.1	0.5	0.1	0.001	0.001	0.005	0.001	90.8	0.1	99.9	6.6
25	4/5/2022	10:02 AM	10:17 AM				Dual HP/LP	48	8	42	8 to 10	MOV_2375.mp4	99.24	99.77	97.85	99.88	0.33	1.0	0.4	2.0	0.3	0.3	0.2	0.6	0.1	0.002	0.001	0.005	0.001	91.5	62.5	99.7	4.7
26	4/5/2022	10:46 AM	11:01 AM				Low Pressure	46	7	44	14 to 16	MOV_2380.mp4	98.80	99.36	94.26	99.99	0.97	0.2	0.1	1.2	0.1	0.4	0.1	1.1	0.2	0.004	0.000	0.014	0.002	77.4	27.7	100.0	12.2
27	4/5/2022	11:19 AM	11:40 AM				Dual HP/LP	42	7	42	18 to 20	MOV_2385.mp4	88.30	90.52	79.42	99.65	3.24	0.3	0.1	1.1	0.2	5.8	3.0	9.8	1.3	0.100	0.040	0.241	0.039	95.2	76.8	99.9	3.1
28	4/5/2022	11:55 AM	12:12 PM				Dual HP/LP	42	8	43	18 to 20	MOV_2390.mp4	93.40	94.85	78.99	99.99	3.78	0.1	0.0	0.9	0.1	1.7	0.1	4.6	1.2	0.021	0.000	0.063	0.017	82.9	0.1	99.9	19.1
29	4/5/2022	12:26 PM	12:41 PM				Low Pressure	46	8	44	18 to 20	MOV_2392.mp4	99.66	99.94	98.64	99.99	0.16	0.2	0.1	0.5	0.0	0.8	0.4	1.2	0.2	0.009	0.003	0.015	0.002	91.1	62.7	100.0	5.8
30	4/5/2022	12:53 PM	1:08 PM				Dual HP/LP	37	10	41	16 to 18	MOV_2396.mp4	98.43	99.11	87.37	99.87	1.02	0.4	0.1	1.0	0.1	0.5	0.2	1.5	0.2	0.005	0.002	0.016	0.002	85.6	3.8	99.9	10.6
31	4/5/2022	1:26 PM	1:41 PM				Low Pressure	43	10	41	22 to 24	MOV_2397.mp4	99.38	99.87	98.10	99.84	0.26	1.5	0.4	3.5	0.5	6.3	2.6	11.7	1.3	0.130	0.042	0.259	0.033	93.0	2.1	99.9	5.6
32	4/5/2022	1:57 PM	2:12 PM				High Pressure	48	9	42	18 to 20	MOV_2398.mp4	99.67	99.95	99.03	99.96	0.12	0.3	0.2	1.1	0.1	1.0	0.6	1.4	0.1	0.013	0.007	0.021	0.002	89.8	68.7	99.9	4.6
33	4/5/2022	2:26 PM	2:42 PM				Dual HP/LP	43	8	48	18 to 20	MOV_2400.mp4	96.17	97.20	87.69	99.03	1.56	0.2	0.1	0.3	0.0	5.5	3.9	7.9	0.6	0.088	0.068	0.127	0.009	95.7	54.4	100.0	2.9
34	4/5/2022	3:16 PM	3:31 PM				Dual HP/LP	49	7	63	10 to 12	MOV_2401.mp4	99.88	99.95	99.19	99.99	0.08	0.2	0.1	0.5	0.0	12.4	9.8	14.6	0.8	0.257	0.180	0.321	0.026	97.2	59.5	100.0	1.8
35	4/5/2022	3:46 PM	4:01 PM				High Pressure	50	7	68	4 to 6	MOV_2402.mp4	99.31	99.80	96.65	99.94	0.36	0.6	0.2	1.8	0.2	0.7	0.3	1.4	0.2	0.009	0.003	0.019	0.003	85.9	27.1	99.8	9.8
36	4/5/2022	4:02 PM	4:17 PM				Low Pressure	40	7	68	4 to 6	MOV_2403.mp4	99.66	99.95	98.94	99.99	0.15	0.5	0.2	1.5	0.2	0.9	0.6	1.3	0.1	0.012	0.009	0.016	0.001	94.5	54.7	100.0	4.6
37	4/5/2022	4:31 PM	4:46 PM				High Pressure	32	9	61	8 to 10	MOV_2404.mp4	99.52	99.91	97.99	99.93	0.24	0.8	0.4	1.2	0.1	0.2	0.1	0.4	0.0	0.003	0.001	0.005	0.001	92.7	64.7	100.0	5.1
38	4/5/2022	4:47 PM	5:02 PM				Low Pressure	37	9	61	8 to 10	MOV_2405.mp4	99.40	99.89	98.85	99.75	0.16	0.5	0.3	1.0	0.1	0.6	0.4	0.9	0.1	0.007	0.004	0.011	0.001	96.2	82.6	100.0	2.1
39	4/5/2022	5:13 PM	5:28 PM				Dual HP/LP	55	7	68	6 to 8	MOV_2406.mp4	99.23	99.78	97.26	99.88	0.31	0.2	0.1	0.4	0.0	1.0	0.7	1.4	0.1	0.010	0.007	0.016	0.001	85.7	55.2	100.0	6.9
40	4/5/2022	5:40 PM	5:55 PM				High Pressure	52	6	67	8 to 10	MOV_2407.mp4	98.35	99.06	91.53	99.64	0.79	1.6	0.8	2.3	0.3	3.1	1.5	26.3	1.0	0.072	0.042	0.108	0.010	94.4	28.5	100.0	4.8
41	4/5/2022	5:55 PM	6:10 PM				Low Pressure	60	6	67	8 to 10	MOV_2408.mp4	99.56	99.88	93.28	99.99	0.46	0.3	0.2	1.4	0.2	0.5	0.1	1.2	0.3	0.005	0.000	0.012	0.003	89.4	36.5	99.8	6.9
42	4/6/2022	8:22 AM	8:37 AM				Dual HP/LP	68	2	79	10 to 12	MOV_2410.mp4	98.51	99.13	91.86	99.99	1.21	0.6	0.1	1.7	0.3	0.9	0.2	13.6	2.0	0.018	0.001	0.417	0.060	90.3	0.1	100.0	8.6
43	4/6/2022	8:51 AM	9:06 AM				High Pressure	37	1	78	12 to 14	MOV_2411.mp4	99.26	99.71	95.26	99.99	0.57	0.4	0.1	0.7	0.1	0.8	0.3	1.3	0.1	0.009	0.002	0.017	0.002	88.9	68.3	100.0	5.7
44	4/6/2022	9:08 AM	9:23 AM				Low Pressure	60	1	78	12 to 14	MOV_2412.mp4	97.88	98.66	95.20	99.05	0.56	0.1	0.1	0.7	0.0	1.1	0.8	1.9	0.1	0.011	0.007	0.017	0.001	94.7	59.2	100.0	4.7
45	4/6/2022	9:40 AM	9:55 AM				Low Pressure	48	3	75	10 to 12	MOV_2413.mp4	98.87	99.48	96.71	99.82	0.52	0.9	0.4	2.1	0.3	0.3	0.1	0.6	0.1	0.004	0.002	0.007	0.001	95.9	87.8	100.0	2.0
46	4/6/2022	10:46 AM	11:01 AM				Dual HP/LP	58	3	73	16 to 18	MOV_2416.mp4	98.66	99.31	95.78	99.92	0.61	0.5	0.2	1.2	0.1	9.0	6.5	21.7	2.1	0.181	0.126	0.523	0.056	97.7	91.7	100.0	1.3
47	4/6/2022	11:44 AM	12:03 PM				Dual HP/LP	46	9	57	16 to 18	MOV_2418.mp4	97.12	97.96	85.06	99.99	3.18	0.8	0.1	3.7	0.7	0.6	0.1	6.5	0.8	0.008	0.000	0.140	0.014	86.5	0.1	100.0	14.4
48	4/6/2022	12:17 PM	12:32 PM				Dual HP/LP	75	9	48	10 to 12	MOV_2419.mp4	97.37	98.22	91.73	99.68	1.23	0.2	0.1	0.8	0.1	7.2	0.2	25.4	6.0	0.134	0.001	0.669	0.143	89.1	25.4	99.9	11.9
49	4/6/2022	12:58 PM	1:13 PM				Dual HP/LP	37	11	49	18 to 20	MOV_2420.mp4	98.55	99.23	96.83	99.75	0.48	1.2	0.6	2.2	0.3	0.3	0.2	0.4	0.0	0.003	0.002	0.005	0.001	86.4	65.1	100.0	6.6
50	4/6/2022	2:14 PM	2:29 PM				High Pressure	40	7	43	12 to 14	MOV_2422.mp4	99.10	99.68	97.87	99.85	0.28	0.1	0.1	0.3	0.0	6.6	4.2	8.5	0.6	0.131	0.090	0.179	0.013	97.0	86.5	100.0	2.2
51	4/6/2022	3:27 PM	3:42 PM				Dual HP/LP	43	12	43	30 to 32	MOV_2423.mp4	99.18	99.74	97.84	99.81	0.31	2.0	1.2	3.3	0.3	0.1	0.1	0.5	0.0	0.001	0.001	0.003	0.000	96.2	6.4	100.0	7.0
52	4/6/2022	4:01 PM	4:16 PM				Low Pressure	50	8	29	26 to 28	MOV_2424.mp4	99.41	99.83	97.99	99.99	0.37	0.8	0.4	1.9	0.2	0.2	0.1	0.4	0.0	0.002	0.001	0.004	0.000	92.3	77.4	100.0	4.1
53	4/6/2022	4:17 PM	4:22 PM				High Pressure	36	8	29	26 to 28	MOV_2425.mp4	99.27	99.80	98.23	99.95	0.27	0.1	0.0	0.2	0.0	0.1	0.0	0.1	0.0	0.000	0.000	0.001	0.000	82.3	53.7	99.6	8.6
54	4/7/2022	7:33 AM	7:48 AM				Dual HP/LP	58	-1	68	10 to 12	MOV_2426.mp4	98.75	99.40	96.77	99.56	0.25	0.3	0.2	0.7	0.1	1.6	1.1	6.4	0.6	0.020	0.010	0.091	0.008	90.8	69.3	100.0	4.9
55	4/7/2022	8:05 AM	8:20 AM				Dual HP/LP	49	-1	67	18 to 20	MOV_2427.mp4	98.43	99.10	95.05	99.99	0.70	0.6	0.1	2.4	0.5	1.6	0.2	9.7	1.7	0.037	0.001	0.298	0.060	86.2	0.1	99.9	8.9
56	4/7/2022	8:32 AM	8:47 AM				Low Pressure	28	-2	72	14 to 16	MOV_2428.mp4	99.10	99.67	97.47	99.86	0.39	0.1	0.1	0.1	0.0	0.7	0.3	1.2	0.2	0.010	0.004	0.022	0.003	94.2	82.2	100.0	3.2
57	4/7/2022	8:59 AM	9:14 AM				Dual HP/LP	61	-1	79	18 to 20	MOV_2429.mp4	97.10	98.00	94.26	99.35	0.79	0.2	0.1	0.3	0.0	2.2	0.5	4.6	0.7	0.031	0.004	0.087	0.014	80.9	0.1	100.0	15.8
58	4/7/2022	9:24 AM	9:39 AM				Dual HP/LP	53	2	70	12 to 14	MOV_2430.mp4	99.13	99.63	95.71	99.99	0.54	0.4	0.1	1.0	0.1	1.3	0.8	1.8	0.2	0.018	0.008	0.029	0.003	85.9	61.0	99.9	6.8
59	4/7/2022	10:00 AM	10:15 AM				Low Pressure	40	5	54	20 to 22	MOV_2432.mp4	99.08	99.67	97.97	99.68	0.27	0.2	0.1	0.4	0.0	0.9	0.5	1.7	0.2	0.013	0.007	0.023	0.003	92.3	74.8	99.9	4.3
60	4/7/2022	10:30 AM	10:45 AM				Dual HP/LP	70	5	50	16 to 18	MOV_2433.mp4	96.31	97.31	70.17	99.87	3.27	0.4	0.1	2.3	0.3	6.5	0.1	24.5	7.5	0.118	0.000	0.643	0.149	74.6	0.1	99.7	22.1
61	4/7/2022	10:55 AM	11:10 AM				Dual HP/LP	42	3	51	18 to 20	MOV_2434.mp4	99.57	99.91	98.26	99.99	0.29	0.5	0.1	2.4	0.3	0.2	0.0	0.6	0.1	0.002	0.000	0.007	0.001	81.3	25.6	100.0	10.3
62	4/7/2022	11:24 AM	11:39 AM				Low Pressure North	37	5	45	18 to 20	MOV_2435.mp4	99.00	99.55	96.22	99.99	0.56	0.5	0.2	1.3	0.1	0.7	0.4	1.0	0.1	0.010	0.006	0.014	0.001	91.5	67.8	99.9	4.4
63	4/7/2022	11:41 AM	11:56 AM				Low Pressure South	43	5	45	18 to 20	MOV_2437.mp4	99.36	99.79	96.54	99.99	0.49	0.6	0.1	1.8	0.3	0.2	0.1	0.8	0.1	0.001	0.000	0.008	0.001	84.6	0.1	100.0	11.6
64	4/7/2022	11:58 AM	12:13 PM				High Pressure	41	5	45	18 to 20	MOV_2438.mp4	99.03	99.56	97.11	99.99	0.64	3.0	0.1	7.0	1.7	0.6	0.1	6.0	1.1	0.009	0.001	0.117	0.020	95.0	62.2	100.0	4.2
65	4/7/2022	12:33 PM	12:48 PM				High Pressure North	34	6	38	22 to 24	MOV_2439.mp4	99.68	99.94	98.36	99.99	0.23	0.3	0.2	0.6	0.1	0.9	0.5	1.5	0.2	0.014	0.004	0.031	0.005	90.6	49.5	100.0	5.0
66	4/7/2022	12:49 PM	1:04 PM				High Pressure South	48	6	38	22 to 24	MOV_2440.mp4	99.75	99.95	99.30	99.99	0.09	0.6	0.2	0.9	0.1	0.9	0.5	1.9	0.2	0.014	0.005	0.034	0.005	89.8	59.8	99.9	5.7
67	4/7/2022	1:08 PM	1:23 PM				Low Pressure	58	6	38	22 to 24	MOV_2441.mp4	99.19	99.71	97.04	99.91	0.46	0.2	0.1	0.5	0.1	0.2	0.1	0.8	0.1	0.002	0.001	0.010	0.002	84.2	35.5	99.9	8.3
68	4/7/2022	1:37 PM	1:52 PM				Low Pressure	31	6	41	20 to 22	MOV_2442.mp4	99.64	99.94	98.71	99.98	0.18	0.4	0.1	1.2	0.2	1.3	0.4	3.3	0.5	0.028	0.008	0.062	0.013	93.4	59.5	100.0	4.8
69	4/7/2022	2:21 PM	2:36 PM				High Pressure	32	9	34	10 to 12	MOV_2443.mp4	98.80	99.42	94.76	99.99	0.54	0.4	0.2	0.8	0.1	0.7	0.3	1.2	0.1	0.009	0.003	0.018	0.002	91.7	74.7	100.0	4.7
70	4/7/2022	2:37 PM	2:52 PM				Low Pressure	39	9	34	10 to 12	MOV_2444.mp4	99.27	99.80	92.67	99.96	0.41	0.3	0.1	1.1	0.1	0.6	0.2	1.0	0.1	0.008	0.002	0.014	0.002	87.8	31.9	100.0	7.6
71	4/7/2022	3:13 PM	3:28 PM				Low Pressure	37	7	37	16 to 18	MOV_2445.mp4	98.57	99.23	96.53	99.87	0.46	0.6	0.2	1.3	0.2	0.3	0.1	0.7	0.1	0.003	0.001	0.010	0.001	87.7	32.2	99.8	6.5
72	4/7/2022	3:49 PM	4:04 PM				Dual HP/LP	68	8	36	20 to 22	MOV_2446.mp4	98.48	99.14	92.52	99.99	0.90	0.3	0.1	1.5	0.2	7.0	0.2	41.4	8.5	0.137	0.001	0.663	0.185	87.9	18.3	99.9	10.2
73	4/7/2022	4:54 PM	5:09 PM				Dual HP/LP	58	11	32	6 to 8	MOV_2451.mp4	98.02	98.78	95.48	99.79	0.97	0.3	0.1	0.9	0.1	1.2	0.1	2.8	0.5	0.013	0.001	0.032	0.006	80.3	0.1	99.3	11.9
74	4/7/2022	5:26 PM	5:41 PM				Dual HP/LP	91	7	42	16 to 18	MOV_2452.mp4	98.73	99.34	81.51	99.95	1.90	1.2	0.4	3.1	0.6	22.6	9.1	148.3	7.9	0.842	0.334	1.423	0.204	96.8	47.8	100.0	2.9
75	4/8/2022	8:08 AM	8:23 AM				Low Pressure	39	-2	66	0 to 2	MOV_2453.mp4	98.29	99.01	96.13	99.42	0.49	1.0	0.6	1.4	0.1	0.7	0.5	0.9	0.1	0.012	0.010	0.015	0.001	95.8	85.8	100.0	1.9
76	4/8/2022	8:24 AM	8:39 AM				High Pressure	30	-2	66	0 to 2	MOV_2454.mp4	99.43	99.87	98.58	99.92	0.25	0.7	0.3	1.8	0.3	0.3	0.1	0.5	0.1	0.004	0.001	0.006	0.001	94.9	71.6	100.0	3.6
77	4/8/2022	9:17 AM	9:35 AM				Dual HP/LP	76	2	55	0 to 2	MOV_2455.mp4	96.73	97.58	62.85	99.99	7.52	0.6	0.1	4.1	0.9	30.0	4.1	189.5	47.2	0.288	0.034	2.630	0.327	94.1	11.0	100.0	9.7
78	4/8/2022	9:45 AM	10:01 AM				Dual HP/LP	83	3	59	0 to 2	MOV_2459.mp4	95.02	96.23	66.03	99.91	5.35	0.2	0.1	2.0	0.3	6.1	0.2	24.0	4.8	0.100	0.001	0.525	0.104	87.1	0.1	100.0	23.7
79	4/8/2022	10:16 AM	10:26 AM				Dual HP/LP	57	8	42	0 to 2	MOV_2460.mp4	99.74	99.95	99.24	99.99	0.15	1.1	0.8	2.0	0.2	0.2	0.1	0.4	0.0	0.001	0.001	0.002	0.000	95.3	6.8	100.0	7.6
80	4/8/2022	10:56 AM	11:11 AM				Dual HP/LP	112	10	29	0 to 2	MOV_2461.mp4	99.44	99.90	96.64	99.97	0.24	0.5	0.4	0.8	0.1	53.6	38.4	71.4	4.8	1.098	0.828	1.358	0.102	96.8	84.8	100.0	1.7
81	4/8/2022	11:26 AM	11:44 AM				Dual HP/LP	112	10	29	0 to 2	MOV_2462.mp4	99.36	99.82	94.10	99.95	0.42	0.5	0.2	2.2	0.1	61.2	23.2	171.8	7.0	1.239	0.291	1.633	0.149	96.5	0.1	100.0	4.1
82	4/8/2022	11:55 AM	12:10 PM				Dual HP/LP	167	12	25	6 to 8	MOV_2463.mp4	99.20	99.72	87.28	99.86	1.10	0.7	0.3	1.4	0.3	53.8	31.5	186.2	12.0	1.104	0.591	1.875	0.306	96.9	45.4	99.9	2.8
83	4/8/2022	12:26 PM	12:41 PM				Low Pressure	50	11	26	4 to 6	MOV_2464.mp4	96.50	97.49	91.54	99.40	1.30	0.1	0.1	0.2	0.0	1.6	0.8	2.6	0.3	0.025	0.013	0.039	0.006	88.8	68.3	99.9	5.1
84	4/8/2022	1:01 PM	1:16 PM				Low Pressure South	37	13	25	4 to 6	MOV_2466.mp4	99.60	99.91	98.56	99.99	0.26	0.3	0.0	1.0	0.2	0.6	0.2	1.1	0.2	0.008	0.002	0.017	0.003	95.1	75.2	99.9	3.1
85	4/8/2022	1:16 PM	1:31 PM				Low Pressure North	36	13	25	4 to 6	MOV_2467.mp4	99.18	99.69	94.35	99.92	0.64	0.5	0.1	1.2	0.2	0.4	0.1	1.2	0.3	0.005	0.001	0.017	0.004	93.7	69.5	100.0	4.2
86	4/8/2022	1:34 PM	1:49 PM				Low Pressure South	20	13	25	4 to 6	MOV_2468.mp4	99.52	99.91	98.47	99.96	0.22	0.2	0.1	0.4	0.0	0.1	0.1	0.2	0.0	0.001	0.001	0.002	0.000	94.9	66.2	99.9	3.1
87	4/8/2022	2:07 PM	2:22 PM				Low Pressure	59	14	23	4 to 6	MOV_2469.mp4	99.78	99.94	98.61	99.99	0.20	0.8	0.3	1.2	0.2	0.5	0.3	1.2	0.2	0.004	0.003	0.011	0.001	92.4	54.4	100.0	6.9
88	4/8/2022	2:23 PM	2:38 PM				Low Pressure	40	14	23	4 to 6	MOV_2470.mp4	99.70	99.95	98.88	99.94	0.12	0.9	0.5	1.2	0.1	0.4	0.3	0.5	0.0	0.003	0.002	0.005	0.000	96.5	14.6	100.0	3.2
89	4/8/2022	3:02 PM	3:17 PM				High Pressure	50	13	21	2 to 4	MOV_2471.mp4	99.21	99.69	88.08	99.99	0.85	1.0	0.4	2.4	0.5	9.4	5.7	26.2	1.7	0.265	0.142	0.406	0.044	94.9	58.3	99.9	4.0
90	4/8/2022	3:19 PM	3:34 PM				High Pressure	63	13	21	2 to 4	MOV_2472.mp4	99.21	99.76	98.03	99.94	0.28	0.2	0.1	0.9	0.1	1.1	0.4	4.6	0.5	0.009	0.004	0.023	0.003	90.4	51.1	100.0	6.4
91	4/8/2022	4:16 PM	4:31 PM				Dual HP/LP	42	15	18	2 to 4	MOV_2474.mp4	98.90	99.52	97.75	99.81	0.34	0.2	0.1	1.8	0.1	2.0	1.2	2.9	0.3	0.034	0.022	0.045	0.004	96.6	42.3	100.0	2.9
92	4/8/2022	4:49 PM	5:04 PM				Low Pressure	30	12	17	8 to 10	MOV_2475.mp4	99.14	99.72	97.70	99.69	0.26	0.6	0.3	1.2	0.1	0.4	0.2	0.6	0.1	0.004	0.002	0.007	0.001	87.2	66.9	99.9	6.1

Appendix B: Validation of the VISR method

The VISR method has been extensively tested using extractive sampling as a control method. The largest blind test was conducted by the Petroleum Environmental Research Forum (PERF), a non-profit organization created to provide a stimulus to and a forum for the collection, exchange, and analysis of research information relating to the petroleum industry. PERF project 2014-10 (Test) was created by participating PERF companies to provide a test platform for various developers/vendors of flare remote sensing technologies (Invitees) to participate in a blind test to evaluate the effectiveness of each technology. The test was administered by John Zink at their test facility in Tulsa, Oklahoma, USA. [redacted] sponsoring PERF companies and Providence Photonics was one of the vendors participating in the PERF test. The results of the PERF test have now been released to the public.

The PERF test consisted of 43 individual test points. Each test point was measured with an extractive system suspended over the flame, as shown in *Figure 15*. With the exception of 3 test points provided as calibration data (per test protocol), the test was completely blind for the participants. The flare performance (Combustion Efficiency), flow rate and fuel composition were not shared with the participants until after their individual results were submitted.

The VISR method performed quite well in the PERF test. *Figure 16* below shows the VISR results compared to the control method (extractive results) across the 43 test points. Overall, the VISR result was within 1% of the extractive result and the accuracy was even better for the higher CE range (above 95%).

Figure 15. VISR method demonstrated as part of the PERF remote flare monitoring blind testing.

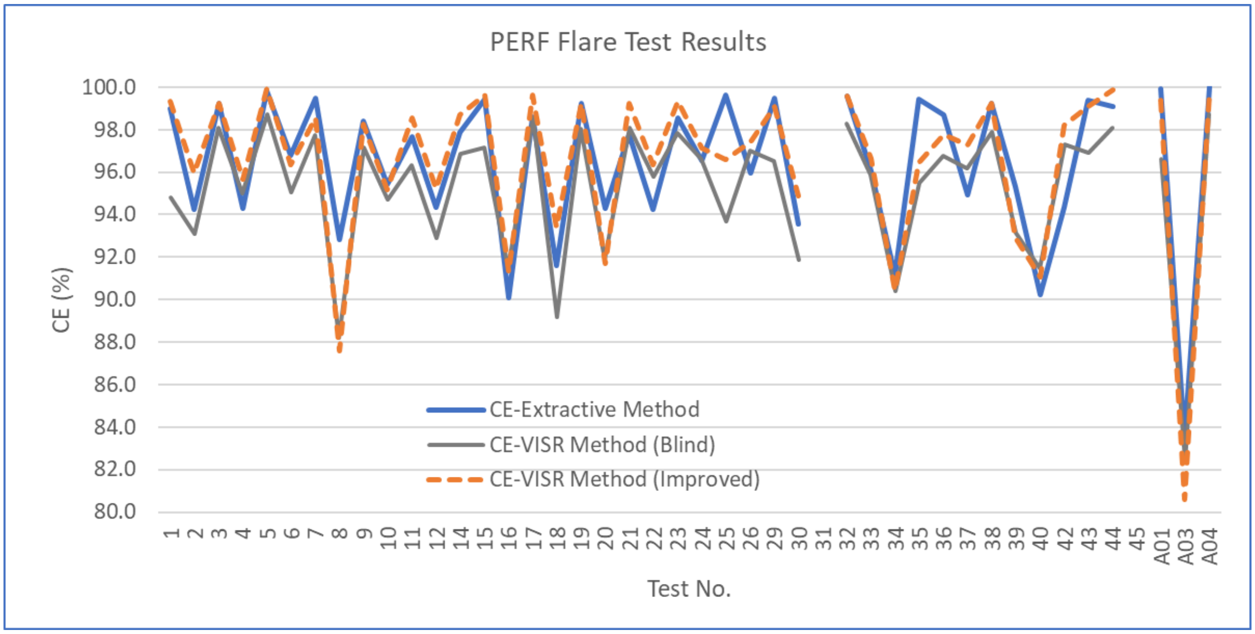

Figure 16. PERF test results, VISR (remote) vs. Extractive.

Note that the CE definition used by VISR was slightly different than what was used for the PERF extractive results. *Equation 1* below shows the calculation used to determine CE from the extractive results:

$$CE\ (\%) = \frac{CO_2(vol\%)}{CO_2(vol\%) + \frac{[CO(ppmvd) + 3\ \times THC(ppmvd)]}{10000}} \times 100$$

Equation 1

The VISR method uses the same equation but excludes the CO component. Extractive testing (including the PERF study) conducted by Providence Photonics, it was shown that the concentration of CO in the combustion plume (especially when CE is greater than 95%) is orders of magnitude lower than either CO2 or THC. Therefore, the effect of excluding CO from the CE equation is negligible.

Some definitions of CE also include soot (IE carbon) in the denominator, which means the presence of smoke will tend to lower CE. The VISR method does not measure carbon soot when determining CE, which is consistent with the definition of CE in a regulatory context.

A systematic negative bias of -0.8% was observed in the VISR results when compared to the extractive results from the PERF test. Providence Photonics has continued developing the CE algorithm since the PERF testing and believes that the systematic bias has been removed. This was confirmed by Providence Photonics by re-running the PERF data with the latest VISR algorithm. More information regarding the validation testing performed on the VISR method can be found in the PERF Report.

Another set of extractive testing was conducted at Zeeco's test facility in Tulsa, Oklahoma, USA and is discussed in a peer reviewed journal article[1].

Appendix C: Combustion Efficiency Versus Destruction Efficiency

With respect to emissions calculations or GHG reporting, it is important to consider the difference between combustion efficiency (CE) and destruction efficiency (DE). The VISR method measures CE, which is a measure of the efficiency of the flame to convert hydrocarbons into carbon dioxide and water. If the combustion efficiency is 100%, then all of the hydrocarbons have been oxidized all the way to carbon dioxide, leaving no hydrocarbons in the post combustion plume. CE will be reduced as the percentage of hydrocarbon in the post combustion plume increases. Destruction efficiency is a measure of the percentage of a compound that is destroyed (IE converted into another form), but not necessarily oxidized to the ultimate combustion product of carbon dioxide and water. In this case, it represents the percentage of hydrocarbons destroyed. The hydrocarbons could be converted to carbon dioxide, carbon monoxide, soot or another compound. As a result, DE is typically higher than CE. For emission inventory purposes, flares are generally deemed to have a DE of 98%, meaning 98% of the hydrocarbons sent to the flare are converted into another form. There is no quantitative method to convert the VISR CE data to DE, however we do have some points of reference. The US EPA Refinery Sector Rule (40 CFR 63.670 (r) equates a CE of 96.5% to a DE of 98%. The rule references the John Zink combustion handbook (Baukal, 2001).

In addition, there have been two major studies which have measured both CE and DE with extractive sampling: the 2010 TCEQ Study and the 2016 PERF Study. Both of these studies were conducted at John Zink's research facility in Tulsa, Oklahoma. Taken collectively, these studies provide 71 individual measurements of CE and DE. *Figure 8* below shows the relationship between CE and DE from these two studies.

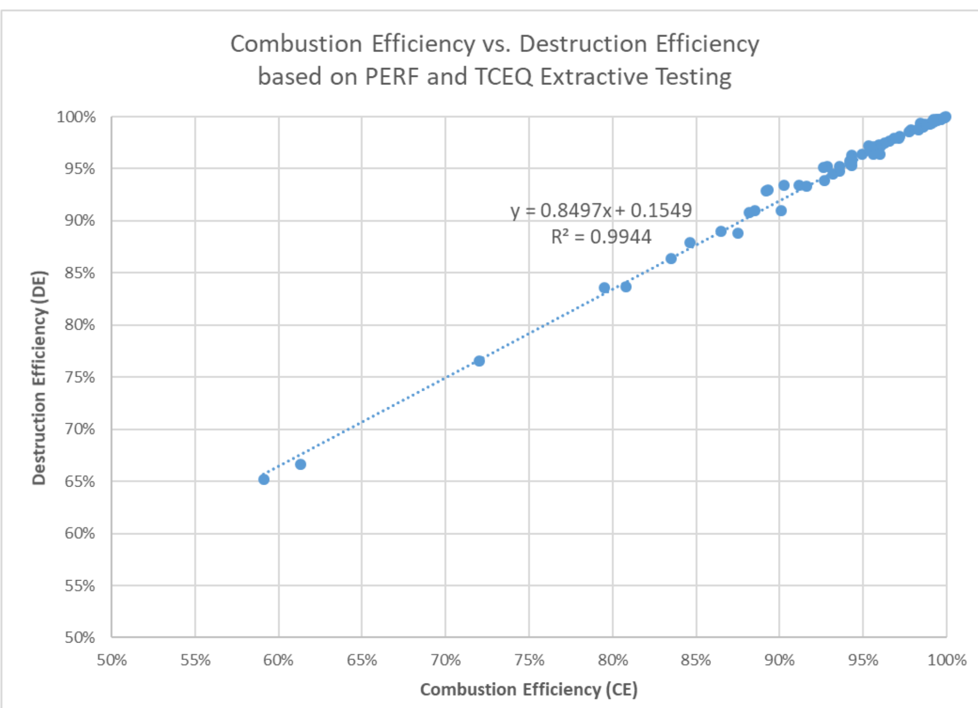

Figure 17. CE vs DE from extractive sampling during PERF and VISR studies.

As demonstrated by the chart, the relationship between DE and CE is quite linear. The fit equation to this data has an R^2 of 0.99. Equation 2 below can be used to convert CE to DE using this correlation:

$$DE\ (\%) = CE\ (\%) * 0.8497 + 0.1549$$

Equation 2

It should be noted that when SI is high and CE appears to be low, the destruction efficiency (DE) may still be high as the hydrocarbons are combusted into soot instead of oxidizing to the ultimate combustion products of water and CO_2. The CE-DE relationship shown in *Figure 8* is established under no smoke conditions. There has not been sufficient study on a similar CE-DE relationship when there is significant smoke in the flare. This equation will be valid for CE within a range of 60% to 99.4%. Above 99.4%, the DE will be capped at 100%. Below 60%, there is no extractive data available to extend the correlation.

PROVIDENCE PHOTONICS

Mantis Performance Report for [redacted] Flare Test

July 2022

Prepared for

[redacted]

PROVIDENCE PHOTONICS PROJECT NO. [redacted]

PREPARED BY
Providence Photonics, LLC | 1201 Main Street, Baton Rouge, LA 70802

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Introduction

[redacted]) retained Providence Photonics, LLC (Providence) to conduct performance measurements with the Mantis flare monitor. The test was funded in part by the DOE ARPA-E REMEDY program to improve the DRE of flares and reduce methane emissions from flares. The objective of the test was to provide a baseline for [redacted] DreamDuo flare.

The flare test was conducted at the [redacted] on July 26th, 2022. This report summarizes the performance results recorded by the Mantis flare monitor.

Background

The Mantis utilizes a multi-spectral midwave infrared imager to measure relative concentrations of combustion gases. The method was designed to be a continuous and autonomous remote flare monitor and can be integrated in the plant control system. In this instance, the Mantis data was recorded locally and retrieved later for reporting purposes.

Results

The results from Mantis measurements are tabulated in **Appendix A** and a summary is provided in *Table 1 below*.

Date	Start Time (Local)	End Time (Local)	Test Description	Distance (m)	Temp (°C)	RH (%)	CE Avg (%)	DRE Avg (%)	SI Avg	FF Avg (m2)	FH Avg (MMBTU/HR)	FS Avg (%)
7/26/2022	10:49 AM	10:53 AM	Test Point 2	145	31	45	98.63	99.30	0.7	197.5	6.77	95.9
7/26/2022	11:04 AM	11:07 AM	Test Point 3	145	31	45	98.90	99.51	0.5	170.2	5.21	96.6
7/26/2022	11:16 AM	11:22 AM	Test Point 4	145	31	45	99.05	99.65	0.5	134.2	3.38	96.2
7/26/2022	11:58 AM	12:02 PM	Test Point 4c	145	31	45	99.09	99.69	0.4	94.8	2.05	96.5
7/26/2022	12:55 PM	1:00 PM	Test Point 5	145	32	39	99.14	99.73	0.5	53.6	1.00	97.1
7/26/2022	1:02 PM	1:07 PM	Test Point 6	145	32	39	99.29	99.85	0.5	31.0	0.54	97.2
7/26/2022	1:09 PM	1:15 PM	Test Point 7	145	32	39	99.13	99.72	0.5	26.9	0.44	97.0
7/26/2022	1:17 PM	1:24 PM	Test Point 8	145	32	39	99.20	99.76	0.4	17.6	0.28	97.1
7/26/2022	1:26 PM	1:32 PM	Test Point 9	145	32	39	99.41	99.91	0.3	13.7	0.19	97.1
7/26/2022	1:39 PM	1:45 PM	Test Point 10	145	32	39	99.49	99.94	0.3	10.7	0.14	97.1
7/26/2022	1:48 PM	1:54 PM	Test Point 4d	145	32	39	99.16	99.74	0.4	87.2	1.91	96.5
7/26/2022	2:10 PM	2:15 PM	Test Point 12a	145	32	39	99.54	99.91	0.6	21.7	0.39	94.4
7/26/2022	2:17 PM	2:20 PM	Test Point 12b	145	32	39	99.66	99.93	0.7	21.6	0.43	95.2
7/26/2022	2:26 PM	2:29 PM	Test Point 12b Repeat	145	33	36	99.58	99.96	0.6	21.7	0.44	96.0
7/26/2022	2:36 PM	2:38 PM	Test Point 13	145	33	36	99.51	99.90	1.2	22.4	0.47	95.4
7/26/2022	2:40 PM	2:43 PM	Test Point 14	145	33	36	99.04	99.57	2.6	21.7	0.50	95.2
7/26/2022	2:55 PM	2:59 PM	Test Point 15	145	33	36	99.60	99.94	0.5	22.9	0.40	94.9
7/26/2022	3:01 PM	3:04 PM	Test Point 16	145	33	36	97.61	98.39	0.5	25.0	0.40	91.3
7/26/2022	3:08 PM	3:14 PM	Test Point 17	145	33	36	99.48	99.84	0.4	14.4	0.22	94.8
7/26/2022	3:18 PM	3:22 PM	Test Point 18	145	35	30	98.95	99.55	0.4	9.2	0.13	94.7
7/26/2022	3:29 PM	3:35 PM	Test Point 19	145	35	30	99.12	99.60	2.3	12.7	0.24	94.6
7/26/2022	3:38 PM	3:42 PM	Test Point 20	145	35	30	99.01	99.48	2.9	18.5	0.39	94.7
7/26/2022	3:43 PM	3:48 PM	Test Point 21	145	35	30	98.60	99.16	5.1	16.2	0.38	94.5
7/26/2022	3:56 PM	4:00 PM	Test Point 22	145	35	30	99.45	99.91	0.6	28.7	0.57	95.4

Table 1: Summary Mantis Results.

Flare Performance Metrics

VISR provides five flare performance metrics at a 1-second data interval:

1. COMBUSTION EFFICIENCY (0 TO 100%): Combustion efficiency (CE) is a measure of the relative concentration of hydrocarbon vs. carbon dioxide in the post combustion gas plume. If there is no hydrocarbon present in the post combustion gas plume, then CE is 100%.
2. SMOKE INDEX (0 TO 10): Smoke index (SI) is a unit-less number which indicates the degree of visible emissions within the combustion envelope. A SI of 0 means no visible emissions are present while a SI of 10 means the flare has heavy black smoke. While SI only represents the degree of visible emissions within the combustion envelope, it is generally correlated to opacity and a SI above 2 indicates that some visible emissions are likely present outside of the combustion envelope.
3. FLAME FOOTPRINT (FT^2): Flame footprint (FF) is a measure of the flame size in square feet. It is not necessarily correlated to the visible flame size as the FF is determined by the radiance, not the visible flame. Note that the orientation of the flame will impact the FF as the depth of the flame will change with viewing angle.
4. FRACTIONAL HEAT RELEASE (BTU/HR): Fractional Heat Release (FH) is a measure of the heat released from flare combustion in the spectral bands monitored by the VISR imager. Although it is not a measure of the total heat release across the entire energy spectrum, FH is expected to be correlated to the total heat release.
5. FLAME STABILITY (0 TO 100%): Flame stability (FS) is a measure of the change in radiance measured by the VISR imager in a 1-second interval. A FS of 100% indicates a flame that has a constant radiance. A low FS value (generally lower than 80%) indicates a flame with significant radiance fluctuation within 1 second interval, suggesting a less stable flame. Variability on a longer time scale will not be described by the flame stability metric.

Data Quality Indicators

The VISR method has two important data quality indicators (DQI) to assess the quality of the measurement. The first is the number of pixels in the flame combustion envelope. The VISR method requires at least 30 pixels to accurately determine the performance metrics of the flame. The VISR device has a fixed focal length, so the number of pixels in the flame is determined by the size of the flame and the distance from the VISR imager to the flame. For this test the flame size was above the minimum number of pixels for all measurements performed.

The second important DQI is the Smoke Index level. As the smoke index increases above 2.0 (this threshold may vary within a range of 1-2 depending on specific flares), visible emissions are generally present in the flame. When visible emissions become significant, the SI value will climb even higher to a maximum value of 10 for thick black smoke. Extractive testing shows that SI values above 3.0 may cause a small negative bias on the CE measurement (< 1%) and SI values above 5 may cause a significant negative bias to CE, as confirmed by testing with an extractive sampling method as a control. Any data points with a smoke index above 3 were removed from the summary tables and **Appendix A** results.

Summary

A flare test was conducted at the [redacted] on July 26th, 2022. The test was funded in part by the DOE ARPA-E REMEDY program to improve the DRE of flares and reduce methane emissions from flares. The objective of the test was to provide a baseline for [redacted] DreamDuo flare. Raw 1-second data and summary data are provided along with this report.

References

1. Yousheng Zeng, Jon Morris & Mark Dombrowski (2015) Validation of a new method for measuring and continuously monitoring the efficiency of industrial flares, Journal of the Air & Waste Management Association, 66:1, 76-86, DOI: 10.1080/10962247.2015.1114045

2. Yousheng Zeng, Jon Morris. (2019, April 2nd). *Precision and Accuracy of the VISR Method for Flare Monitoring*. Air Quality Measurement Methods and Technology, Durham, North Carolina, United States.

Appendix A: Results

Date/Time					Conditions			Efficiency (%)					Smoke Index (0-10)				Flare Footprint (m^2)				Fractional Heat (MMBTU/HR)				Flame Stability (%)			
ID	Date	Start Time (CST)	End Time (CST)	Test Description	Distance (m)	Temp (°C)	RH (%)	CE Avg	DRE Avg	CE Min	CE Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD	Avg	Min	Max	SD
1	7/26/2022	10:49 AM	10:53 AM	Test Point 2	145	31	45	98.63	99.30	95.46	99.62	0.55	0.7	0.2	2.2	0.3	197.5	9.3	274.3	31.6	6.77	0.11	8.46	1.17	95.9	70.0	100.0	3.4
2	7/26/2022	11:04 AM	11:07 AM	Test Point 3	145	31	45	98.90	99.51	93.16	99.82	0.71	0.5	0.1	1.1	0.2	170.2	107.5	209.1	25.4	5.21	2.85	7.02	1.17	96.6	90.8	100.0	1.9
3	7/26/2022	11:16 AM	11:22 AM	Test Point 4	145	31	45	99.05	99.65	95.68	99.72	0.48	0.5	0.1	3.5	0.3	134.2	22.8	324.5	30.5	3.38	0.28	5.08	0.96	96.2	24.1	100.0	4.7
4	7/26/2022	11:58 AM	12:02 PM	Test Point 4c	145	31	45	99.09	99.69	95.57	99.95	0.30	0.4	0.1	1.4	0.2	94.8	60.4	181.6	16.7	2.05	1.33	3.20	0.43	96.5	68.3	99.8	2.8
5	7/26/2022	12:55 PM	1:00 PM	Test Point 5	145	32	39	99.14	99.73	98.36	99.60	0.15	0.5	0.1	1.6	0.2	53.6	39.4	119.2	6.8	1.00	0.74	1.21	0.09	97.1	56.2	100.0	3.2
6	7/26/2022	1:02 PM	1:07 PM	Test Point 6	145	32	39	99.29	99.85	98.36	99.73	0.19	0.5	0.1	0.9	0.1	31.0	21.2	39.0	3.4	0.54	0.38	0.67	0.05	97.2	91.0	100.0	1.5
7	7/26/2022	1:09 PM	1:15 PM	Test Point 7	145	32	39	99.13	99.72	98.13	99.86	0.30	0.5	0.1	1.4	0.1	26.9	18.0	33.1	3.0	0.44	0.34	0.55	0.04	97.0	79.4	99.8	1.9
8	7/26/2022	1:17 PM	1:24 PM	Test Point 8	145	32	39	99.20	99.76	97.13	99.71	0.33	0.4	0.1	1.1	0.1	17.6	11.5	24.2	2.8	0.28	0.19	0.39	0.04	97.1	67.4	100.0	2.4
9	7/26/2022	1:26 PM	1:32 PM	Test Point 9	145	32	39	99.41	99.91	98.66	99.83	0.21	0.3	0.2	0.6	0.1	13.7	8.8	17.0	1.5	0.19	0.13	0.24	0.02	97.1	92.6	100.0	1.4
10	7/26/2022	1:39 PM	1:45 PM	Test Point 10	145	32	39	99.49	99.94	97.83	99.75	0.29	0.3	0.2	0.5	0.1	10.7	7.9	12.7	1.0	0.14	0.11	0.17	0.01	97.1	92.7	99.9	1.4
11	7/26/2022	1:48 PM	1:54 PM	Test Point 4d	145	32	39	99.16	99.74	98.36	99.83	0.16	0.4	0.2	2.0	0.2	87.2	18.5	155.6	11.5	1.91	0.19	2.31	0.25	96.5	65.0	100.0	2.8
12	7/26/2022	2:10 PM	2:15 PM	Test Point 12a	145	32	39	99.54	99.91	96.69	99.99	0.43	0.6	0.1	1.5	0.2	21.7	5.2	84.1	6.9	0.39	0.06	0.60	0.11	94.4	12.4	99.9	6.9
13	7/26/2022	2:17 PM	2:20 PM	Test Point 12b	145	32	39	99.66	99.93	96.88	99.99	0.43	0.7	0.2	1.8	0.3	21.6	5.2	32.3	6.1	0.43	0.05	0.63	0.15	95.2	50.6	99.9	4.5
14	7/26/2022	2:26 PM	2:29 PM	Test Point 12b Repeat	145	33	36	99.58	99.96	98.86	99.99	0.25	0.6	0.1	1.4	0.2	21.7	17.6	26.0	1.5	0.44	0.33	0.54	0.04	96.0	89.9	100.0	2.0
15	7/26/2022	2:36 PM	2:38 PM	Test Point 13	145	33	36	99.51	99.90	98.46	99.99	0.34	1.2	0.6	2.5	0.4	22.4	17.8	101.6	6.8	0.47	0.36	0.63	0.05	95.4	43.9	99.8	4.8
16	7/26/2022	2:40 PM	2:43 PM	Test Point 14	145	33	36	99.04	99.57	97.13	99.99	0.67	2.6	0.8	4.4	0.8	21.7	13.0	92.9	8.0	0.50	0.34	0.77	0.08	95.2	6.3	99.9	7.0
17	7/26/2022	2:55 PM	2:59 PM	Test Point 15	145	33	36	99.60	99.94	97.54	99.99	0.36	0.5	0.1	1.1	0.2	22.9	17.4	29.2	2.0	0.40	0.32	0.51	0.03	94.9	84.0	99.8	2.6
18	7/26/2022	3:01 PM	3:04 PM	Test Point 16	145	33	36	97.61	98.39	87.41	99.92	2.67	0.5	0.2	1.3	0.1	25.0	4.2	32.4	3.5	0.40	0.01	0.51	0.07	91.3	21.9	99.8	9.4
19	7/26/2022	3:08 PM	3:14 PM	Test Point 17	145	33	36	99.48	99.84	93.56	99.99	0.76	0.4	0.2	0.9	0.1	14.4	7.6	19.4	1.8	0.22	0.10	0.32	0.03	94.8	14.6	100.0	6.7
20	7/26/2022	3:18 PM	3:22 PM	Test Point 18	145	35	30	98.95	99.55	96.33	99.72	0.66	0.4	0.1	0.8	0.1	9.2	6.3	12.1	1.1	0.13	0.09	0.19	0.02	94.7	83.5	99.8	2.7
21	7/26/2022	3:29 PM	3:35 PM	Test Point 19	145	35	30	99.12	99.60	97.37	99.99	0.64	2.3	0.6	4.1	0.7	12.7	8.9	92.8	4.2	0.24	0.14	0.36	0.03	94.6	6.8	99.9	5.6
22	7/26/2022	3:38 PM	3:42 PM	Test Point 20	145	35	30	99.01	99.48	97.16	99.99	0.87	2.9	0.9	6.4	1.1	18.5	12.3	318.5	20.1	0.39	0.28	0.95	0.07	94.7	0.1	99.8	7.4
23	7/26/2022	3:43 PM	3:48 PM	Test Point 21	145	35	30	98.60	99.16	97.53	99.98	1.80	5.1	0.8	7.6	1.8	16.2	6.6	92.8	6.1	0.38	0.13	0.71	0.13	94.5	0.1	99.9	6.2
24	7/26/2022	3:56 PM	4:00 PM	Test Point 22	145	35	30	99.45	99.91	98.42	99.99	0.27	0.6	0.2	1.7	0.2	28.7	19.4	115.5	9.2	0.57	0.37	0.86	0.08	95.4	17.1	100.0	8.3

ANNEX E: Supply Chain Study Results Letter, Submitted September 19, 2023

Operator Survey of Supply Chain Delays for Equipment Needed for EPA Proposed NSPS OOOOb Methane Rule

Operator Survey of Supply Chain Delays for Equipment Needed for EPA Proposed NSPS OOOOb Methane Rule

From June through September of 2023, the American Petroleum Institute (API), American Exploration and Production Council (AXPC), Interstate Natural Gas Association of America (INGAA), Independent Petroleum Association of America (IPAA), and GPA Midstream Association (the "Industry Trades") conducted an operator survey of supply chain delays for components and equipment necessary to comply with the Environmental Protection Agency's (EPA) proposed rule "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review." To comply with antitrust guidelines the survey was blinded, and data was gathered and complied by a third party consultant, John Beath Environmental.

The EPA's OOOOb New Source Performance Standard (the "methane rule") is a complex rule that will apply to many thousands of facilities in producing basins across the country. Because of the wide variety of conditions faced by these facilities, the challenges in acquiring equipment due to ongoing COVID-induced supply chain delays, and additional proposed rules which will apply to these sources such as EPA's revisions to Subpart W of the Greenhouse Gas Reporting Program (GHGRP) that will also require equipment, **operators need a reasonable timeline based on a December 6, 2022 applicability date to come into compliance with the final methane rule.**

Operator Survey of Supply Chain Delays for Equipment Needed for EPA Proposed NSPS OOOOb Methane Rule

Responses to the survey included information from 11 basins; a majority of responses included information from the Permian Basin. The responses suggest that operators have the greatest supply chain concerns with pneumatics, control devices, storage vessels, associated gas, and fugitive emissions components.

The survey found that current backorder times for components range from 6+ to 24+ months. Implementation of the proposed methane rule is expected to increase current backorder times by an additional 6+ months. A November 15, 2021 applicability date is expected to substantially exacerbate the challenges of equipment acquisition over a December 6, 2022 applicability date.

The survey results indicate that reasonable compliance timelines, based on a December 6, 2022 applicability date, would need to allow a minimum of 12 to 26 months for operators to come into compliance with the final methane rule, as appropriate given supply chain backlogs for each affected facility.

Current and Anticipated Supply Chain Delays

- Current backorder is generally up to 12 months across affected facilities with additional lead time needed for specialized equipment.
- Finalization of NSPS OOOOb is expected to add a minimum of 6 months of additional backorder time across affected facilities.

Affected Facility	Current Procurement Lead Time ("Backorder") is Delayed	Anticipated Backorder upon NSPS OOOOb Finalization Compared to Existing Lead Time
Pneumatic Controllers and Pumps	• Up to 12 months across equipment options. • Electrical transformers and instrument air skids are experiencing variable delays with 24+ months indicated.	• Add 6 to 12 months
Control Device Provisions	• Up to 12 months for both control devices and other equipment (monitoring, etc.)	• Add 6 to 12 months for control devices and • Add 6+ months for other equipment.
Storage Vessels	• Up to 12 months for steel tanks, vent header control valves • Up to 24 months for VRUs and • Up to 30 months for PVRVs & thief hatches.	• Add 6+ months across equipment
Associated Gas	• Up to 18 months for VRUs, gas compressor skids	• Add 6 to 12 months
Fugitive Emissions Components	• Up to 12 months across monitoring options.	• Add up to 6 months
Other (miscellaneous equipment)	• Up to 18 months for VFDs	• Add 6 to 12 months for VFDs

Recommended OOOOb Compliance Timelines by Affected Facility

Affected Facility / Category	EPA Proposed Compliance Timeline	Anticipated Supply Chain Delay Upon Finalization *(Current lead time + additional anticipated lead time)*	Industry Trades Recommended Compliance Timeline
Pneumatic Controllers & Pumps	60 days	18 - 36 months	26 months
Control Devices and Closed Vent Systems	60 days	18-24 months	20 months
Associated Gas	60 days	30 months	24 months
Fugitive Emissions Components	60 days	18 months	12 months
Storage Vessels	30 - 60 days	18 - 36 months	26 months

API's February 13 comment letter[1] included anecdotal reports of members' supply chain constraints. This survey quantitatively expands on the supply chain issues raised to demonstrate the need for reasonable compliance timelines.

These recommended compliance timelines account only for supply chain delays and do not contemplate the additional time needed to install equipment. The recommendations reflect the realities of the supply chain, balanced with the urgency of aggressive industry action to achieve compliance with OOOOb and reduce emissions.

While this survey evaluated supply chain delays relative to OOOOb compliance and did not contemplate compliance with OOOOc, given the scope of the proposed rules and available data, similar supply chain constraints are anticipated to continue beyond the OOOOc implementation timeframe.

[1] *https://www.regulations.gov/comment/EPA-HQ-OAR-2021-0317-2428*

Equipment & Services Included by Affected Facility

- Survey responses included equipment and services for various compliance options for each affected facility (listed below).
- The survey included estimated equipment counts, supplier market, and supply chain delays.

Pneumatic Controllers & Pumps • Electrical Transformers • Solar Equipment • Generator Skids • Instrument Air Skids • Electrical Valves/Controllers • Replacement Pumps • Replacement Controllers • ECAT System • Nitrogen Gas	**Control Devices & Closed Vent Systems** • Flares • Enclosed Combustion Devices • Flow Meters • Backpressure Valves • Calorimeters • Third-party Testing: Performance, Net Heating Value (NHV), Opacity • Automatic Pilot Light • Thermocouples • Piping for Closed Vent System	**Storage Vessels** • Steel Tanks • Pressure-Vacuum Relief Valves (PVRVs) & Thief Hatches • Vent Header Control Valve • Vapor Recovery Units (VRUs)*
Associated Gas • VRUs* • Methane Pyrolysis Skids • Gas Compressor Skids • Gas to Liquids Skids • Liquefied Natural Gas Production Skids	**Fugitive Emissions Components** • Optical Gas Imaging (OGI) Cameras • OGI Camera Technicians • Third-party OGI Monitoring • Third-party Alternative Screening Technology Monitoring • Continuous Monitoring Systems • Replacement Piping Components • Handheld Methane Detectors	**Other (Miscellaneous Equipment)** • Variable Frequency Drives (VFDs) • Cabling (Electric/Communications) • Engineering Analysis (Associated Gas, Pneumatic Pumps, etc.) • Eductor Skid (for compressors)

*VRUs were considered separately for Storage Vessels and Associated Gas since size and design may differ.

Estimated Equipment Counts Needed for NSPS OOOOb Compliance

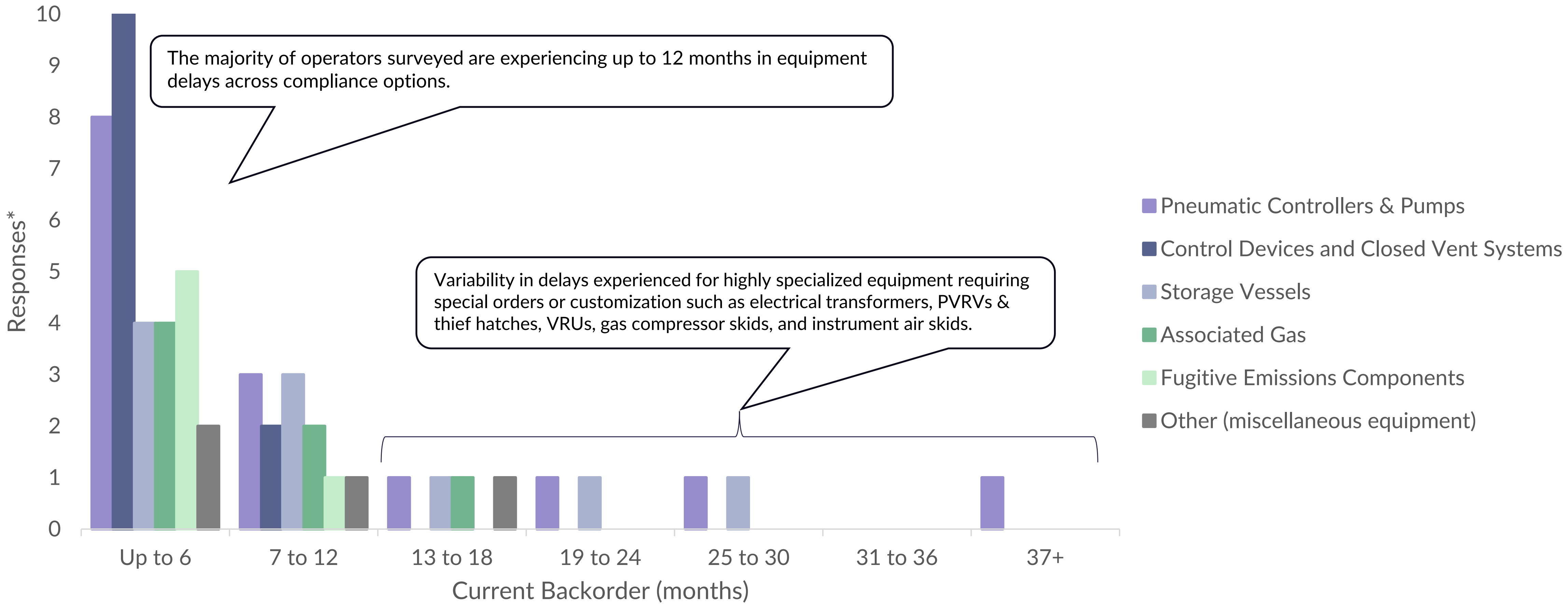
- **Pneumatic Controllers & Pumps**
  - Variety of responses highlight the need for multiple compliance options (i.e., no “one size fits all” solution).
  - 69% of responses indicated that instrument air skids would be needed.
  - Responses continue to indicate that a variety of power generation options will need to be used.
- **Control Devices & Closed Vent Systems**
  - 82% of responses indicated that flow meters would be needed.
  - 27% or more of responses indicated that third-party services (performance testing, NHV testing, or opacity monitoring) were being investigated for use.
- **Storage Vessels**
  - PVRVs & thief hatches were key equipment needed and were not considered in EPA’s cost analysis.
  - 29% of responses indicated that steel tanks would be needed, possibly as replacements for fiberglass tanks to facilitate a closed vent system. Replacement tanks were not considered in EPA’s cost analysis.
- **Associated Gas**
  - While operators support the concept of other types of beneficial use, responses indicated that operators were not planning to implement alternative technology options proposed by EPA (methane pyrolysis, gas to liquids, liquefied natural gas). The costs of alternative use options were not considered in EPA’s cost analysis.
- **Fugitive Emission Components**
  - Responses indicated that most operators were planning to implement their own OGI monitoring program (OGI cameras and technicians). A shortage of OGI technicians was also noted in the responses, and for gas processing operators, availability of qualified OGI camera technicians could be further limited based on the proposed certification and audit requirements in Appendix K. EPA’s cost analysis assumed that operators would use a third-party service.

Survey Results Compared to Previous API Comments

- Since the February 13, 2023 comment deadline, equipment backorder has generally remained the same or worsened.
- A reasonable compliance timeline of 12 to 26 months is needed based on a December 6, 2022 applicability date. Additional time would be needed if EPA maintains the November 15, 2021 applicability date.

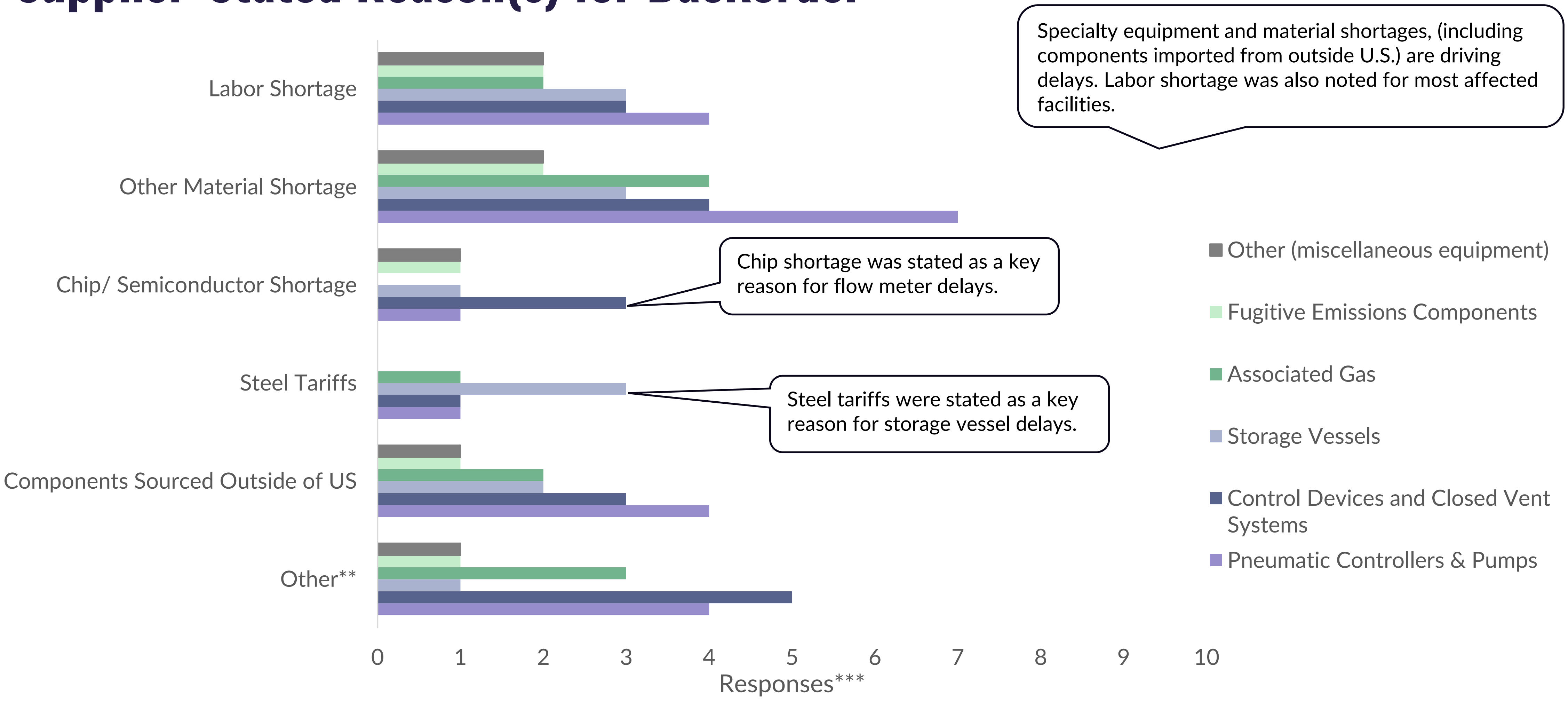
Supply Chain Item	Survey Results (August 2023)	Previous API Comments (February 2023)	Summary of Comparison
Control Device Backorder	Up to 6 months: 75% 7 to 12 months: 25%	3 to 4 months	Backorder has increased by up to 8 months.
Flow Meter Backorder	Up to 6 months: 83% 7 to 12 months: 17%	6 to 8 months	Backorder remains approximately 6 to 8 months.
Flow Meter Installation Timeline (Hot Tap)	Up to 2 weeks: 50% 3 to 4 weeks: 33% 12+ weeks: 17%	Up to 4 months	Survey results may not reflect hot tap installations.
Instrument Air Skids Backorder	Up to 6 months: 58% 7 to 12 months: 25% 19+ months: 17%	8 to 12 months	Backorder has increased by up to 7 months.
Solar Panels Backorder	Up to 6 months: 80% 7 to 12 months: 20%	18 to 24 months	Backorder has decreased by 6 to 12 months.

Current Procurement Lead Time



*Responses by affected facility based on maximum count for each backorder timeframe.

Supplier-Stated Reason(s) for Backorder*

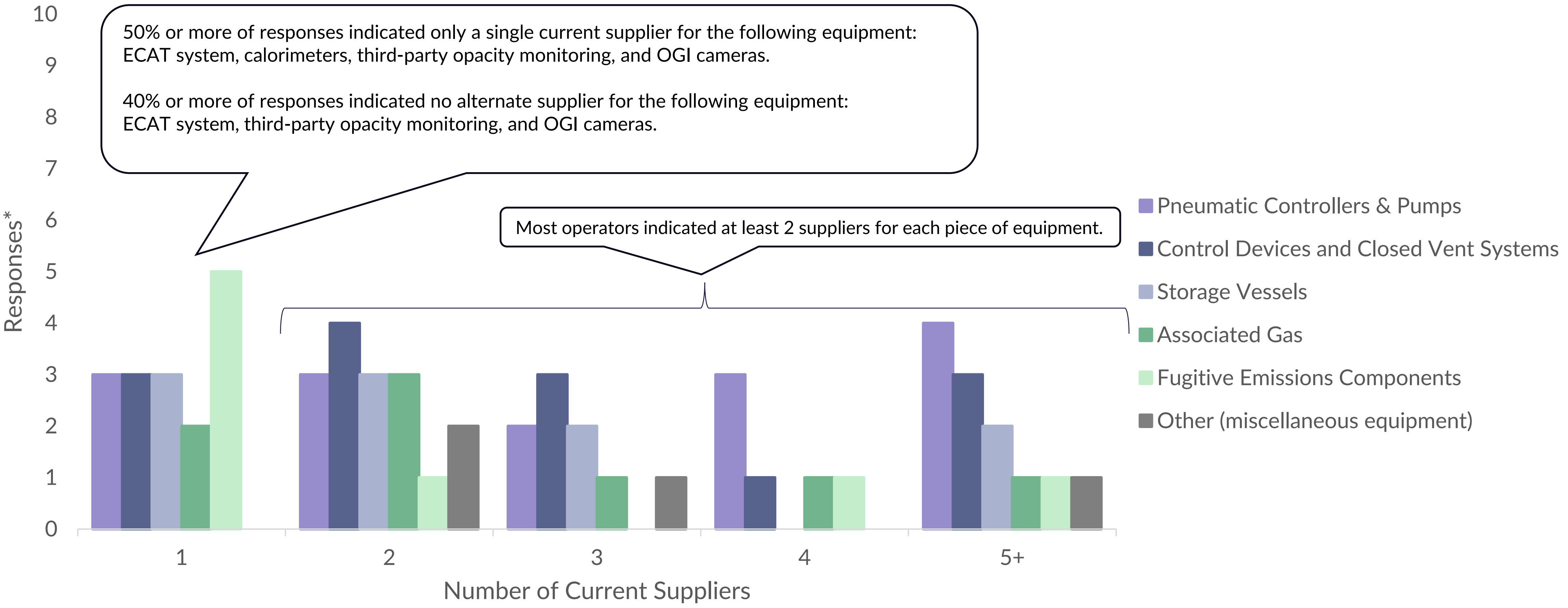


* Responses could indicate more than one reason for backorder delays

** Other reasons vary by control option but include: "Fabricator backlog"; "Standard lead time"; "Limited inventory as order is customized"; "Engineering design required for proper equipment function".

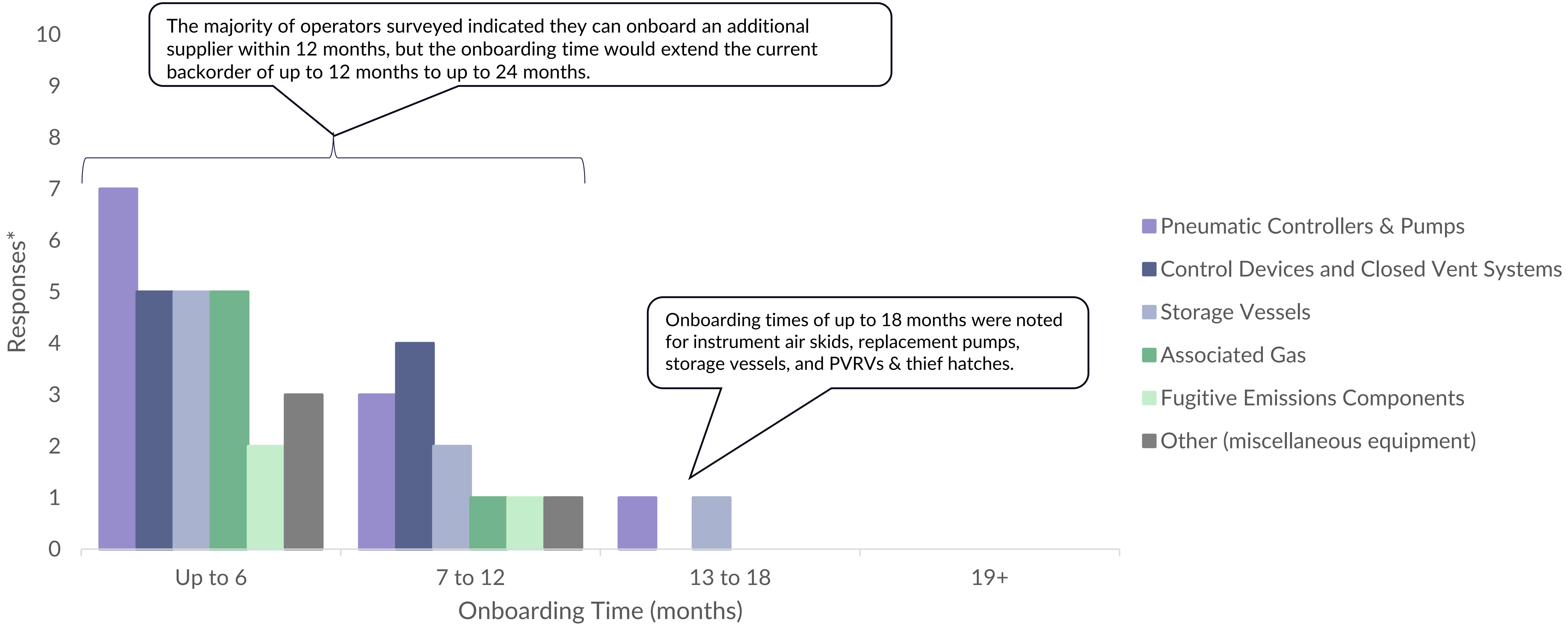
*** Responses based on maximum count for each reason.

Supplier Market



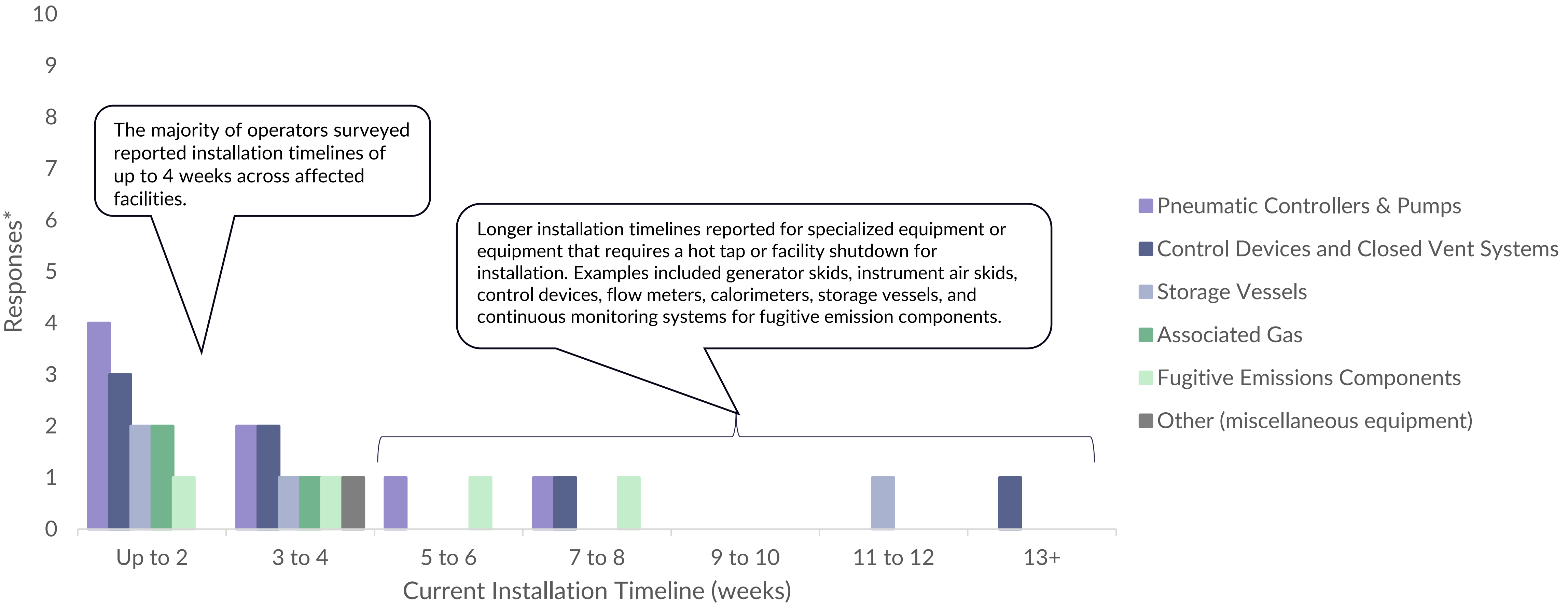
*Responses by affected facility based on maximum count for each number of current suppliers.

Onboarding Time for an Additional Supplier



*Responses by affected facility based on maximum count for each onboarding timeframe.

Current Installation Timelines



*Responses by affected facility based on maximum count for each installation timeline.

Reason(s) for Installation Timelines

* Responses could indicate more than one reason for backorder delays
** Other reasons vary by control option but include: "Engineering evaluation needed"; "Normal construction timeline"; "Weather, road conditions".
*** Responses based on maximum count for each reason.

ANNEX F: API Assessment of Properly Functioning and Malfunctioning Intermittent Bleed Pneumatic Controllers

Note: Data for this analysis is included separately within this docket in pdf format

ANNEX F

Analysis to Support Amendment to Calculation 3 for Intermittent Bleed Devices Monitoring

EPA should amend Equation W-1C to more accurately reflect available empirical data on emissions from properly functioning pneumatic controllers. This proposed amendment is consistent with data contained in Annex A, the API study "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States," and data from the University of Texas,[1] both indicating that malfunctioning intermittent controllers are the primary source of measured emissions; the API pneumatic controller study data indicates it is approximately 85%.

Methods

The UT data[2,3] (304 controllers) and the API data (265 controllers) on natural gas driven intermittent bleed pneumatic controllers were reanalyzed to simulate the use of an IR camera to segregate equipment into malfunctioning and properly functioning controller categories and an average emission calculated for each category after segregation.

Controllers were separated into three groups based on time series behavior, where the detection threshold of the OGI camera was assumed to be 0.9 scfh (~17 g/hr). A sensitivity analysis was conducted to assess the impact of the assumed OGI detection threshold on the results.

Controller categories:[4]

- **Not Malfunctioning**:
    - **Low:** average value of the time series was less than the assumed detection threshold of the camera
    - **Proper:** Either
        - **Return to zero/baseline**: average value was at or above the detection threshold and the last value of the time series was below the threshold, or
        - **Baseline prior to actuation, but measurement terminated during actuation**: average value was at or above the detection threshold and at least half of the data points are less than the threshold.
- Otherwise **Malfunctioning**

The low category represents the equipment that would be viewed as "properly operating" irrespective of time series behavior because emissions would be undetected. The proper category represents equipment that would be viewed as having an actuation associated with emissions, but the actuation would terminate. The "not malfunctioning" category is the combined groups of low and proper. These should be indistinguishable through inspection, since OGI inspection results would be ambiguous as to whether a controller is emitting constantly below the detection limit of the camera or functioning

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[1] http://dept.ceer.utexas.edu/methane/study/datasets3.cfm Data downloaded September 2023.

[2] Ibid.

[3] All pneumatics in UT study were included as intermittent, though there were observations of both low and high continuous bleed devices intermingled. The result of this aggregation increases the properly operating emission factor through the inclusion of low-bleed continuous results that are below the assumed OGI detection threshold.

[4] Files attached dividing those time traces into low, proper, and malfunctioning categories for each the UT and the API data set provides visual inspection to assess implications of these criteria on the time series disaggregation.

properly. The malfunctioning category are the set of observations that are neither categorized as low nor proper. Both studies indicated that malfunctioning intermittent controllers were the majority of measured emissions, including ~85% in the API pneumatic controller study data.[5]

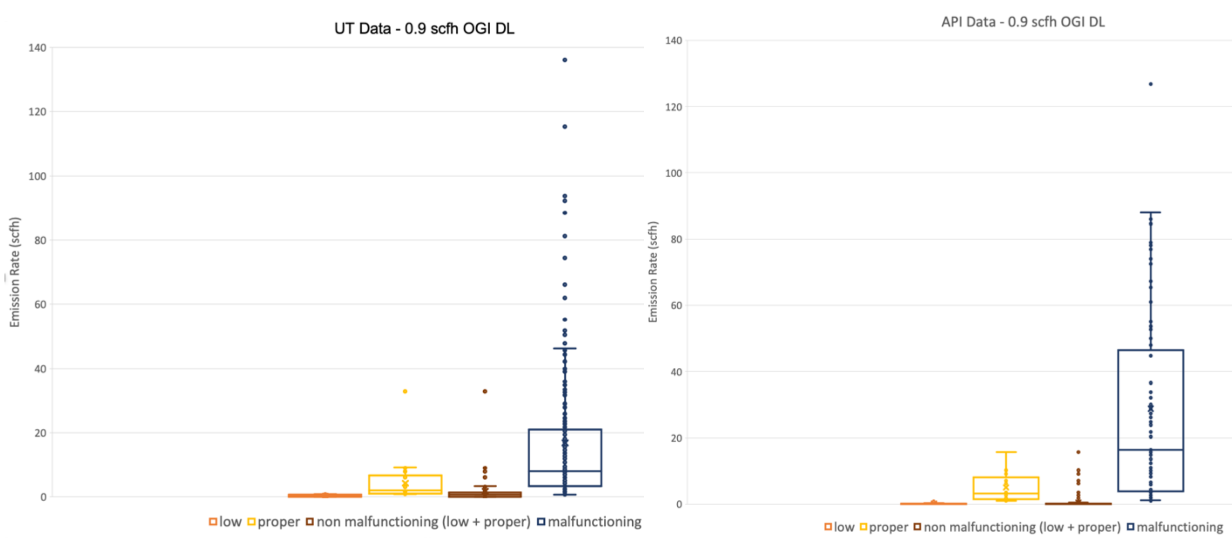
Results

The categorization with OGI camera assumed detection threshold of 0.9 scfh results in a revised set of properly functioning and malfunctioning emission factors of 0.9 and 20.0 scfh, respectively, which would result in a revised equation W-1C as below.

$$E_i = GHG_i \times \left[\sum_{z=1}^{x}\{20.0 \times T_{mal,z} + 0.9 \times (T_{t,z} - T_{mal,z})\} + (0.9 \times Count \times T_{avg})\right] \ (Rev.Eq.W - 1C)$$

The box and whisker plots in Figure 1 show the low, proper, non-malfunctioning, and the malfunctioning average measurements for the UT, API, and combined UT/API data and Table 1 provides the average and median values from each. As expected, each series is skewed.

Figure 1: Top Left – UT data; Top Right – API Data; Bottom – Combined UT + API data



[5] API Study "Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States."

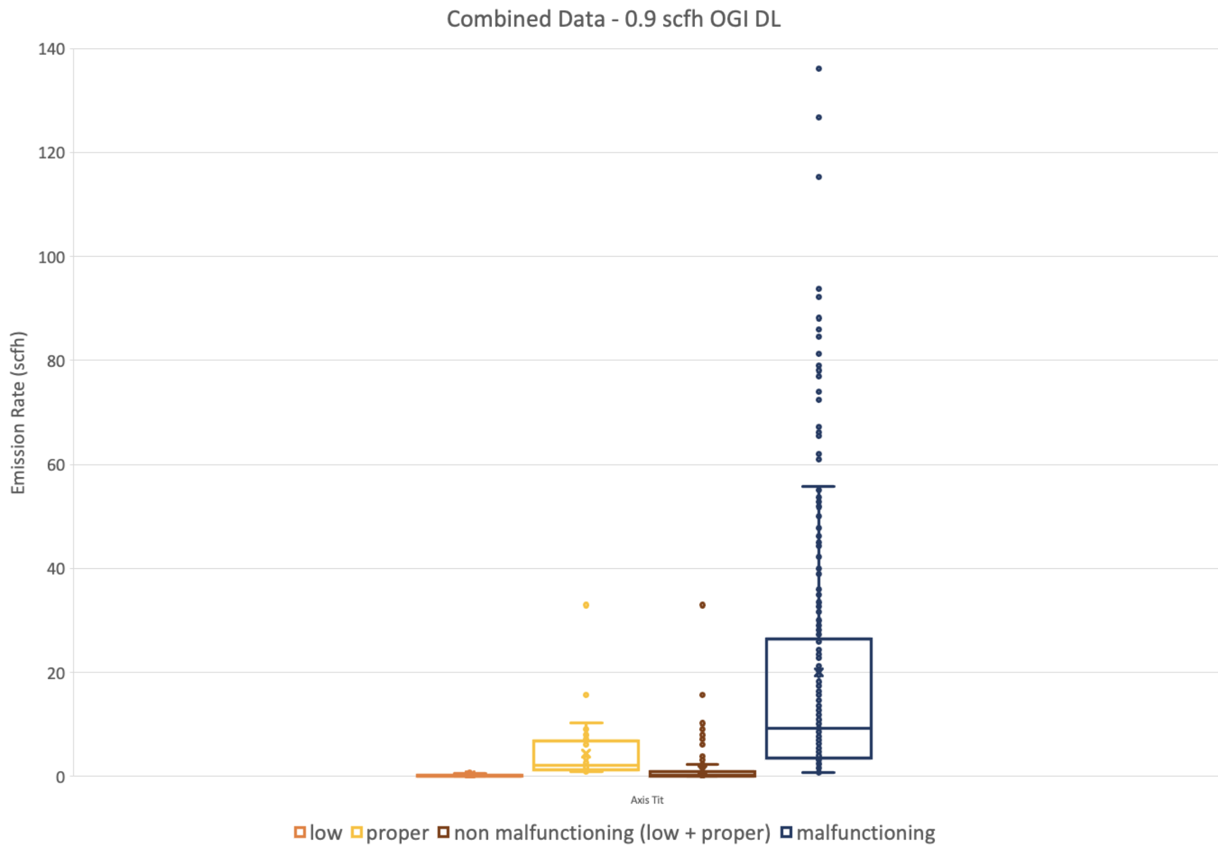


Table 1: Average and median emission rates (scfh) for the low, proper, non-malfunctioning and malfunctioning groups for each the UT, API and combined data sets along with equipment counts in each category.

	Low (scfh) [count]	Proper (scfh) [count]	Non-Malfunctioning (scfh) [count]	Malfunctioning (scfh) [count]
UT – Avg	0.3 [62]	4.3 [36]	1.8 [98]	16.5 [206]
API – Avg	0.1 [171]	5.0 [13]	0.5 [184]	28.8 [81]
Combined – Avg	0.2 [233]	4.4 [49]	**0.9 [282]**	**20.0 [287]**
UT – Median	0.3	2.0	0.7	8.0
API - Median	0.0	2.5	0.0	16.4
Combined - Median	0.0	2.2	0.0	9.3

The non-malfunctioning average emission rate in this segregation of equipment is 0.9 SCFH (68% lower than the proposed factor). The average emission rate of the designated malfunctioning equipment is 20.0 (24% higher than the proposed factor). This results in an overall emission per controller of 10.5 SCFH.

Overall, these results are quite consistent with those from the API pneumatic controller study, insofar as most of the emissions are attributable to the malfunctioning equipment. However, the method of segregating functioning from malfunctioning is different, resulting in a higher properly operating emission factor than the factor proposed in that study analysis shown in Table 2 below. The revised factor of 0.9 SCFH, though larger than the previously proposed factor from the API pneumatic controller study is still significantly lower than the proposed factor in the GHGRP Subpart W proposal.

Table 2: Comparison of the data analyses (former and this work) to proposed emission factors.

	API Study Report Average Emission Rate (SCFH)	API Reanalysis Average Emission Rate (SCFH)	Subpart W Proposed Factors (SCFH)	All data Reanalysis Average Emission Rate (SCFH)
Properly Functioning	0.28	0.5	2.82	**0.9**
Malfunctioning	24.1	28.8	16.1	**20.0**
Average of all equipment	9.25	9.1	-	10.5

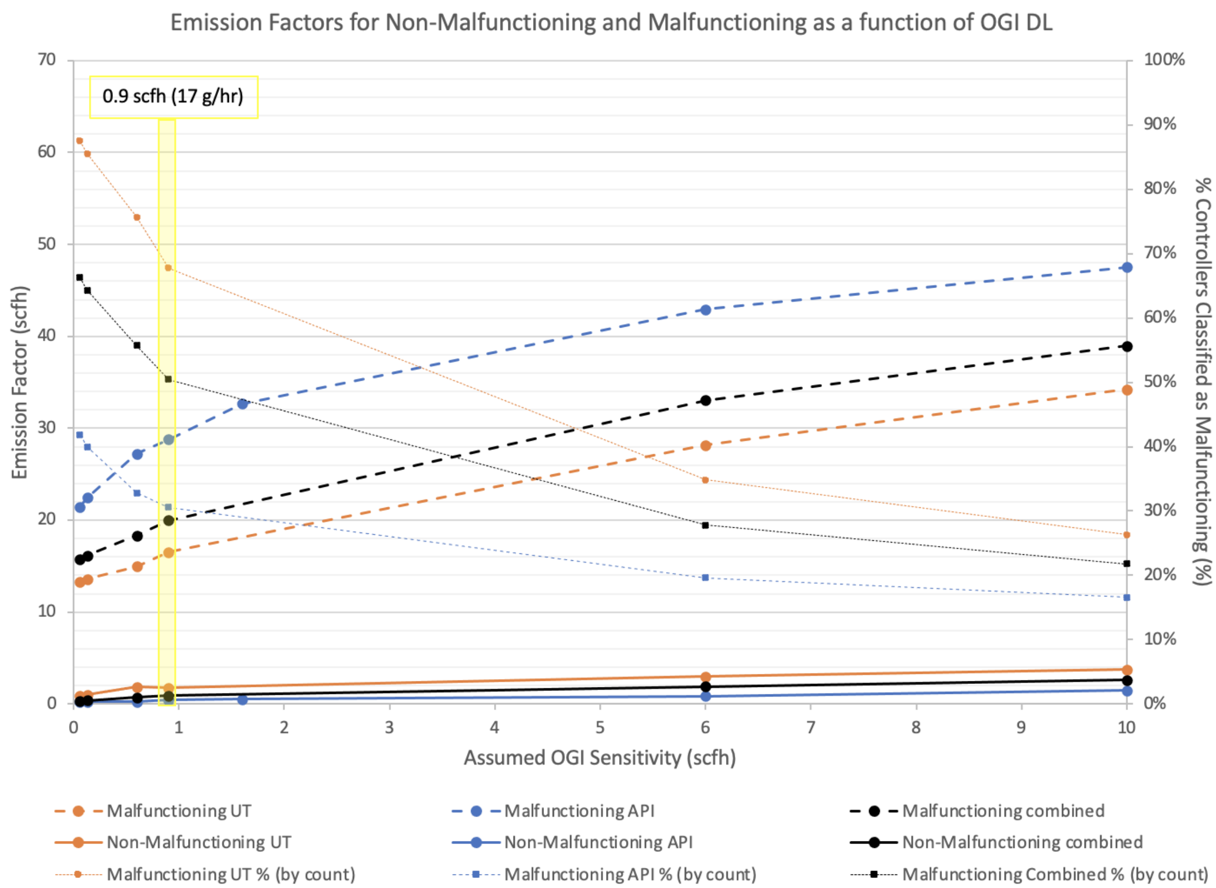
One important limitation of the analysis on the UT data is that the time series are much shorter (~2 minutes in duration on average). However, the proposed rule requires an inspection period of 2 minutes.[6]

Sensitivity Analysis

A sensitivity analysis was performed to assess the impact of selecting a theoretical OGI detection limit of 0.6 SCFH. The results are shown in the figure below.

Figure 2: Data categorized as described in methods, with varying assumed detection threshold of OGI from 0.13 scfh to 10 scfh. Dashed lines show the variation of the malfunctioning pneumatic controller average (left axis), solid lines show the variation of the non-malfunctioning (properly operating) pneumatic controller average (left axis), and the dotted lines show the % of controllers that would be classified as malfunctioning under the different detection threshold scenarios (right axis). UT data are shown in orange, API data in blue, and the combined data are shown in black.

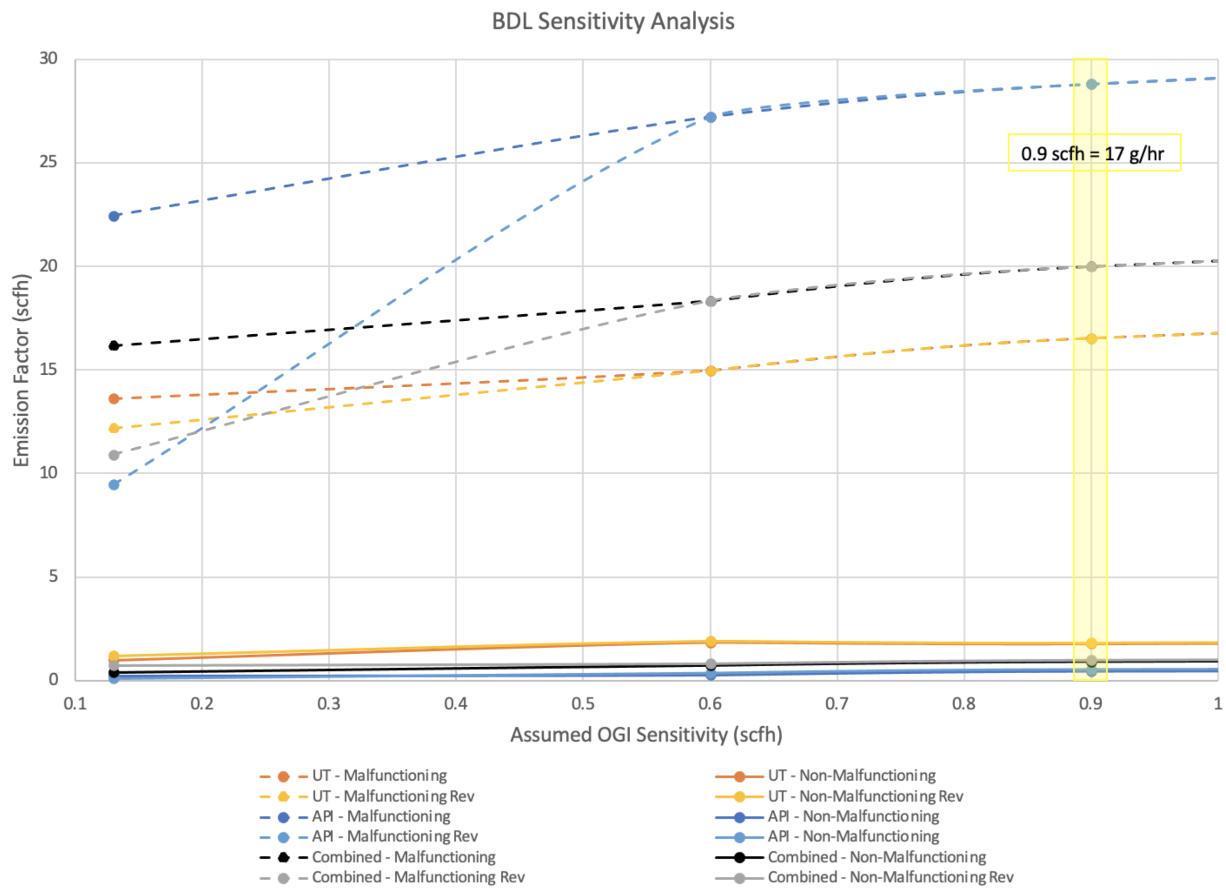
[6] "You must use one of the monitoring methods specified in § 98.234(a)(1) through (3) except that the monitoring dwell time for each device vent must be at least 2 minutes or until a malfunction is identified, whichever is shorter. A device is considered malfunctioning if any leak is observed when the device is not actuating or if a leak is observed for more than 5 seconds during a device actuation. If you cannot tell when a device is actuating, any observed leak from the device indicates a malfunctioning device."



The assumed detection threshold exceeds 10 scfh before the non-malfunctioning (properly operating) average emission reaches 2.82 scfh (proposed factor).

Similarly, a sensitivity analysis was performed to assess the impact of including instrument reported "zeroes" as zeroes. Data substitution was performed to replace all instances of zero with 0.13 scfh to represent the minimum detection limit of the high flowsampler employed in both studies. As shown in Figure 3, there are minor impacts to average emissions for detection thresholds for OGI below ~0.6 scfh, but there is no impact on the proposed range of emission factors.

Figure 3: Data categorized as described in methods, with varying assumed detection threshold of OGI from 0.13 scfh to 1 scfh under two scenarios: 1) data are used as reported and 2) zeroes are substituted with the instrument MDL of 0.13 scfh. Dashed lines show the variation of the malfunctioning pneumatic controller average (left axis) and solid lines show the variation of the non-malfunctioning (properly operating) pneumatic controller average (left axis). UT data are shown in dark orange with the revised data in light orange, API data in dark blue with the revised data in light blue, and the combined data are shown in black with the revised data shown in grey.



BDL Sensitivity Analysis
30
25
20
15
10
5
0
0.1
0.2
0.3
0.4
0.5
0.6
0.7
0.8
0.9
1
Emission Factor (scfh)
Assumed OGI Sensitivity (scfh)
0.9 scfh = 17 g/hr
UT - Malfunctioning
UT - Malfunctioning Rev
API - Malfunctioning
API - Malfunctioning Rev
Combined - Malfunctioning
Combined - Malfunctioning Rev
UT - Non-Malfunctioning
UT - Non-Malfunctioning Rev
API - Non-Malfunctioning
API - Non-Malfunctioning
Combined - Non-Malfunctioning
Combined - Non-Malfunctioning Rev