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January 31, 2022

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

ATTN: Docket ID EPA-HQ-OAR-2021-0317
Proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" including Proposed 40 CFR 60, Appendix K

Dear Administrator Regan:

The American Petroleum Institute (API) respectfully submits the attached comments on the Environmental Protection Agency's (EPA) proposed "Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review" (86 FR 63110, November 15, 2021). This submittal includes comments on the associated proposed Appendix K to 40 CFR Part 60, "Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging".

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 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.

Reducing methane emissions is a priority for our industry and 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 programs, phased out the use of high-bleed pneumatic controllers, and reduced emissions associated with flaring – voluntarily and under federal and state regulations. In addition, API supports industry-led initiatives, such as The Environmental Partnership, to build on the progress industry has made to reduce emissions and continuously improve environmental performance. Founded in 2017, The Partnership has grown to nearly 100 oil and natural gas companies committed to continuously improving their environmental performance by taking action, learning about best practices and technologies, and fostering collaboration. Collectively, the coalition represents over 70% of total U.S. onshore oil and natural gas production and the program is being implemented in 41 of 50 states. Each year, the participating companies report[1] their implementation of the program's six Environmental Performance Programs, including programs for leak detection and repair, gas-driven pneumatic controllers, liquids unloading, compressors, pipeline blowdowns and flare management.

API supports the cost-effective direct regulation of methane from new and existing sources across the supply chain, and directionally supports the EPA proposal to reduce VOC and methane emissions. We especially appreciate EPA's inclusion of an alternate fugitive emissions monitoring option that allows for use of advanced detection technologies. The ability to take advantage of new and emerging technologies allows for monitoring programs that can more effectively identify and address larger emission events. Our comments include suggestions to further enhance the alternate monitoring framework.

In our review of the proposal, API considered the effectiveness of emission reduction strategies, safety, feasibility, operability, and cost, and where appropriate, we have recommended alternative approaches. As no rule text has been provided in this initial proposal, our comments are based on our best understanding of the requirements as they have been described in the preamble. This assessment could be modified once the requirements are provided in EPA's supplemental proposal. We encourage EPA to provide adequate time for stakeholders to review and comment on the supplemental proposal that is accompanied by regulatory text.

As further outlined in our comments, we do not believe the proposal publication date can set the Subpart OOOOb new source applicability date because the proposal lacks proposed regulatory text. Without regulatory text, affected facilities cannot know with certainty what regulatory requirements EPA has proposed and are thus unable to reasonably plan to comply with the final rule. The new source applicability date should be set when proposed regulatory text is published in the Federal Register as part of EPA's supplemental proposal.

With respect to proposal requirements for new (NSPS OOOOb) and existing (EG OOOOc) sources, we generally support, with recommended changes to Appendix K and its application, the provisions for fugitive emissions monitoring at well sites, compressor stations, and gas processing plants. The proposed Appendix K Optical Gas Imaging (OGI) protocol is not appropriate for use in the production and transmission sectors, where OGI monitoring specifications should continue to be based on NSPS OOOOa requirements. With our recommended modifications to Appendix K, we support its application for gas processing plants, petroleum refineries, and similar facilities.

In addition to fugitive emissions monitoring requirements, we also generally support, with certain modifications, the proposal requirements for new and existing pneumatic pumps, storage vessels,

[1] https://theenvironmentalpartnership.org/annual-reports/

reciprocating compressors, centrifugal compressors (other than existing centrifugal compressors located in Alaska), gas well liquids unloading, and oil well associated gas.

With respect to proposed requirements for pneumatic controllers, we generally support EPA's proposal for new and existing gas processing plants and for new well and compressor station surface sites, provided there is an option to route vented emissions to a control device. We provide recommended changes to the applicability of pneumatic controller requirements for existing well sites and compressor stations and to the definition of modification.

API's support of the EPA proposed requirements assumes that EPA provides adequate implementation schedules for certain types of modifications under OOOOb and for retrofitting existing sources under OOOOc.

API is committed to working with EPA and the Administration as it develops and finalizes regulations that are cost-effective, facilitate innovation and further the progress made in reducing emissions, to ensure that the oil and natural gas industry can continue to provide the world with the affordable, reliable energy it needs while reducing emissions and addressing the risks of climate change.

If you have any questions regarding the content of these comments, please contact Cathe Kalisz at kaliszc@api.org.

Sincerely,

Attachments

cc:
Joe Goffman - EPA
Tomas Carbonell - EPA
Peter Tsirigotis - EPA
David Cozzie - EPA
Steve Fruh - EPA
Karen Marsh - 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 and Proposed Appendix K)

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

January 31, 2022

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

1.0 INTRODUCTION

API supports the direct regulation of methane for new and existing oil and natural gas sources and remains committed to working with EPA and the Administration to identify cost-effective emission control opportunities. We support the goal of promoting environmental justice, and our members are committed to constructive interactions among industry, regulators, and surrounding communities that may be disproportionately impacted.

These comments provided herein focus on technical and feasibility challenges with certain provisions described by EPA for proposed NSPS OOOOb and EG OOOOc. Our members look forward to continued dialogue and engagement as EPA works towards the supplemental proposal.

The major concerns identified by our members during this initial comment period include the following:

- **EPA took a very rare step when it issued this preamble-only proposal. The absence of regulatory text underscores the need for EPA to reset the applicability date for the proposed rules.** The current proposal's NSPS OOOOb applicability date means the inventory of affected facilities is currently growing (particularly existing facilities that are modified) without known compliance obligations, as there is no formal regulatory text to follow. The new source applicability date should be set when proposed regulatory text is published in the Federal Register, and EPA must provide sufficient opportunities for public comment, including on elements of the currently available portion of the rule, when definitions, applicability, and other relevant details are available in regulatory text. Furthermore, given the lack of regulatory text and the short comment period timeframe, we have not had an opportunity to fully analyze the Regulatory Impact Analysis (RIA) and the overarching cost effectiveness of the proposed rule. We will continue to pursue and provide more detailed input when we see the regulatory text in the supplemental proposal.

- **OGI monitoring protocols for production facilities and compressor stations should be based on NSPS OOOOa requirements, not Appendix K.** While API supports the use of Optical Gas Imaging (OGI) technology, Appendix K as drafted is unnecessarily burdensome for utilization in upstream production facilities, gathering and boosting compressor stations, and transmission compressor stations. Comments offered below (refer to Comment 4.0) expand on our concerns and outline some of the initially identified feasibility challenges in greater detail. The requirements specified in NSPS OOOOa that are currently used by operators have consistently proven to be effective and are more appropriate for use in upstream applications. Accordingly, we recommend EPA revise its proposal to limit the applicability of Appendix K to refineries; gas plants; and, potentially, similar larger process operations in other industries.

- **Significant modifications to Appendix K are necessary for the protocol to be feasible for implementation at refineries and natural gas processing plants.** Included in Attachments A and B are comments and suggested edits to allow the Appendix K protocol to be effectively implemented for use at refineries and gas processing plants. API's recommended changes are intended to proactively address concerns that the proposed requirements will result in difficulty in finding and retaining adequate numbers of qualified senior OGI operators; that the monitoring, training, and proposed QA/QC requirements are overly burdensome and will not lead to more effective leak detection; and that the ownership of various requirements, particularly the recordkeeping requirements, are unclear and unnecessarily burdensome. The recommended changes also aim to make the Appendix K requirements more straightforward and efficient.

- **While we support reducing emissions from pneumatic controllers, the proposed provisions for pneumatic controllers must be re-evaluated.** We support moving towards non-emitting controllers for completely new construction surface sites; however, EPA has made no provision for addressing modifications at existing locations. The technical feasibility and cost effectiveness for moving towards non-emitting controllers from gas driven controllers fundamentally changes how an operator would approach the control strategy and operation of assets. As such, we offer EPA our suggestions for addressing NSPS modifications and for the retrofit of existing facilities under Emission Guidelines (EG).

- **Advanced leak detection technologies should be specified as an alternative BSER in addition to use of OGI and Method 21 (M21).** Allowing new leak detection technologies increases flexibility in how operators identify leaks and other process upsets. Allowing alternate technologies to be considered BSER will facilitate continued innovation in methane detection technology capabilities.

- **Guidance issued to state programs along with the Emission Guidelines should allow a minimum 3-year implementation period.** Operators with thousands of oil and gas facilities will need adequate time to plan for retrofits and obtain control devices or other specialized equipment, all while dealing with potential supply shortages. Additionally, the precedent for recognizing and providing adequate phase-in is well established. For example, EPA existing source rules under NESHAP (Subparts HH and ZZZZ), which require replacement or retrofit of existing applicable sources in the oil and gas sector, provided a minimum 3-year phase-in to complete work and establish compliance. Some emissions sources like pneumatic controllers may require a longer implementation period (even longer than three years) depending on the finalized regulatory requirements. Lastly, the ongoing limitations of the global supply chain may likely hinder operators' ability to obtain control devices and specialized equipment like solar panels. API strongly encourages EPA to ensure the formal regulatory text creates a feasible and reasonable pathway for operators to comply.

- **EPA should streamline all recordkeeping and reporting.** Within this proposal, EPA is soliciting numerous comments regarding information on the number and types of records operators should maintain and report to EPA. 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 locations 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 affected facilities, which API does not support. We acknowledge and appreciate EPA's streamlining of recordkeeping and reporting in the 2020 Technical Rule updates and support the inclusion of provisions such as these which maintain environmental control standards and assure compliance with less administrative burden.

- **EPA should grant equivalency for state programs across emission sources for NSPS OOOOb.** Given EPA has described many requirements that are consistent with those at the state level (e.g., CO, NM, and CA), EPA should allow for certain state provisions to be deemed equivalent for the proposed NSPS OOOOb where it is appropriate to do so for LDAR and other emission control provisions.

As explained in Comment 11.1, when using the terms "proposal" or "standards" in these comments it does not constitute a "proposed rule" or "emission standard" for purposes of triggering applicability under CAA § 111(a)(2).

2.0 PNEUMATIC CONTROLLERS

Due to the critical nature of pneumatic controllers for safety and operation of oil and gas facilities, we offer the following comments for EPA's consideration in crafting requirements that provide adequate flexibility for solutions to reduce pneumatic controller emissions. Unfortunately, there is not a "one-size fits all" solution, and EPA should allow an array of options for reducing pneumatic controller emissions.

Some specific technical challenges with EPA's described proposal for use of "zero-emitting" controllers which must be addressed under both NSPS OOOOb and EG OOOOc include:

- issues with facilities securing adequate electric grid power (as described in Comment 2.5);
- potential creation of net emissions increases due to on-site natural gas or diesel fired generators (as described in Comment 2.6);
- reliability risks associated with unproven solar-power systems including battery storage (as described in Comment 2.7); and
- hiring or training of personnel with expertise in the installation, use, and maintenance of electronic controllers, which will likely need to be done by a licensed electrician.

2.1 EPA should re-evaluate the proposed standards for pneumatic controllers at both new and existing facilities.

We support the concept of moving towards non-emitting controllers for the collection of pneumatic devices located at completely new construction sites provided an array of control options are allowed (refer to Comment 2.2) and there is a sufficient phase-in period (refer to Comment 2.11). However, we are unable to assess the feasibility of proposed requirements for modified sites because EPA has not delineated how modification of controllers is determined given the new control strategy proposed under NSPS OOOOb. We offer our solution in Comment 2.4.

For existing pneumatic controllers, we believe it is most appropriate to focus on conversion to non-emitting controllers at facilities with the largest number of controllers and with readily accessible grid power. We do not believe EPA should require a complete phaseout of properly functioning low bleed and intermittent controllers at existing facilities, as discussed further in Comments 2.9 and 2.10.

2.2 EPA should allow for the use of “non-emitting” pneumatic controllers versus “zero-emitting” pneumatic controllers.

While the change in terminology may appear subtle, EPA should amend its proposal to allow the use of “non-emitting” instead of “zero-emitting” controllers and allow for various technologies to achieve “non-emitting” status including the option of routing certain controllers to an existing combustion device if it is technically feasible to do so.

Even with this additional flexibility to route controllers to a combustion device, operators will need to evaluate the design and functional needs of the equipment at each site and determine the most appropriate path forward for achieving the “non-emitting” threshold defined for controllers. In remote locations without access to grid power, operators may require an approach that includes multiple solutions to achieve a “non-emitting” standard.

EPA should acknowledge and allow a more flexible approach for reducing emissions from pneumatic controllers for new and modified locations than what has been initially described in the proposal. Multiple options to reduce emissions include the following:

- pneumatic controllers driven by compressed instrument air,
- electric controllers,
- mechanical controllers, and
- routing natural gas controllers to a process, sales line, or combustion device.

2.2.1 State precedents allow flexibility in control options.

Colorado allows all options mentioned above and describes them as “non-emitting” in 5 CCR Regulation 7, Part D, Section III.

> *III.B.10. (State Only) "**Non-emitting Controller**" means a device that monitors a process parameter such as liquid level, pressure or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to: no-bleed pneumatic controllers, electric controllers, mechanical controllers and routed pneumatic controllers.*
>
> *III.B.12. (State Only) "**Routed Pneumatic Controller**" means a pneumatic controller that releases natural gas to a process, sales line or to a combustion device instead of directly to the atmosphere.*

The proposed New Mexico Oil and Gas Sector Ozone Precursor Pollutants Rule[1] (Proposed 20.2.20.7 January 20, 2022) also uses the term "non-emitting controllers" to describe all these options which API prefers to "zero-emitting".

> *"**Non-Emitting Controller**" means a device that monitors a process parameter such as liquid level, pressure, or temperature and sends a signal to a control valve in order to control the process parameter and does not emit natural gas to the atmosphere. Examples of non-emitting controllers include but are not limited to instrument air or inert gas pneumatic controllers, electric controllers, mechanical controllers and Routed Pneumatic Controllers.*
>
> *"**Pneumatic controller**" means a device that monitors a process parameter such as liquid level, pressure, or temperature and uses pressurized gas (which may be released to the atmosphere during normal operation) and sends a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.*
>
> *"**High-Bleed Pneumatic Controller**" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits in excess of 6 standard cubic feet per hour (scfh) of natural gas to the atmosphere.*
>
> *"**Low-Bleed Pneumatic controller**" means a continuous bleed pneumatic controller that is designed to have a continuous bleed rate that emits less than or equal to 6 scfh of natural gas to the atmosphere.*
>
> *"**Intermittent pneumatic controller**" means a pneumatic controller that is not designed to have a continuous bleed rate but is designed to only release natural gas above de minimis amounts to the atmosphere as part of the actuation cycle.*

[1] https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/Attachment-1-NMED-Proposed-Part-20.2.50-January-20-2022-Version.pdf

*"**Routed Pneumatic Controller**" means a pneumatic controller of any type that releases natural gas to a process, sales line, or to a combustion device instead of directly to the atmosphere.*

2.3 Under NSPS OOOOb, EPA should consider amending the affected facility definition to be the collection of pneumatic controllers at a well site or compressor station.

In the 2012 and 2016 NSPS for the oil and gas sector, EPA defined the affected facility as a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh (also referred to as a high-bleed controller). Given the control option was to use a device of similar function with a lower bleed rate, a single controller being the affected source was a technically feasible approach to reduce emissions.

In this proposal, EPA is fundamentally changing the control strategy for pneumatic devices, such that the control option occurs for the collection of pneumatic controllers at a facility by requiring design of the pneumatic system to be non-emitting. Converting a single pneumatic controller to a non-emitting device typically requires that all controllers at the facility be converted to non-emitting devices. Even by EPA's own cost analysis, EPA assumed the control options would occur at the site level and would not occur for an individual controller. Therefore, API suggests that EPA re-evaluate the definition for natural gas driven pneumatic controller affected facility to be considered as a collective versus an individual controller under NSPS OOOOb.

API is supportive of the use of non-emitting controllers for newly constructed well sites, tank batteries, and compressor stations. We offer the suggested affected facility definition based on current NSPS OOOOa language as follows:

Each pneumatic controller affected facility ~~not located at a natural gas processing plant~~, which is the collection of natural gas driven pneumatic controllers that vent to the atmosphere located at a well site, centralized production facility, or compressor station.

2.4 Under NSPS OOOOb, modification for the collection of natural gas driven pneumatic controllers should be defined similar to what EPA has defined for the collection of fugitive components at well sites and compressor stations.

As mentioned, the new proposed control standards under NSPS OOOOb are designed to occur at a site or system level and not by individual controller. Therefore, installing a single pneumatic controller at an existing surface site should not trigger the requirement for retrofitting all controllers to the non-emitting standard. Given the fundamental change in control strategy, EPA must re-evaluate the affected facility definition for controllers and what actions constitute a modification at the site level (and not controller level).

As with any equipment, pneumatic controllers break from time to time and must be replaced. To manage controller maintenance and more easily determine if a modification has occurred, API requests that a modification to a collection of natural gas driven pneumatic controllers be defined similar to how EPA has defined modification in 40 CFR 60.5365a(i) and (j) for well sites, tank batteries, and compressor stations which is summarized as follows:

Collection of natural gas driven pneumatic controllers located at	Actions that Trigger Modification for Pneumatic Controllers to Non-emitting
Well Site	▪ A new well is drilled at an existing well site; ▪ A well at an existing well site is hydraulically fractured; or ▪ A well at an existing well site is hydraulically refractured.
Centralized Production Facility	The above actions listed under well site occur at the tank battery or a well site that sends production to the tank battery.
Compressor Station	▪ An additional compressor is installed at a compressor station; or ▪ One or more compressors at a compressor station is replaced by one or more compressors of greater total horsepower than the compressor(s) being replaced. When one or more compressors is replaced by one or more compressors of an equal or smaller total horsepower than the compressor(s) being replaced, installation of the replacement compressor(s) does not trigger a modification of the compressor station.

Under the above outlined concept, when a modification occurs, the operator would be required to retrofit the collection of pneumatic controllers at the well site, tank battery, or compressor station to non-emitting controllers. As described earlier, a non-emitting controller could include a natural gas controller routed to a process, sales line, or combustion device. Sufficient time will be required to phase-in these retrofits after NSPS OOOOb is finalized.

2.5 Technical Challenges with Grid Power Requirements

2.5.1 Access to grid power must be limited to commercially available onsite connections with sufficient and reliable power.

EPA must clarify that "access to power" means that commercial line power is available onsite, sufficient to cover the power/capacity requirements of the non-emitting pneumatic controller design of the facility, and which provides reliable and consistent coverage. It is not always logistically feasible to electrify a location from the grid due to issues outside of an owner/operator's control. These challenges include right-of-way (ROW) issues for placement of power lines, a landowner's right to not install power lines on their property[2], and/or distance from an available power line that contains sufficient power and capacity to connect the facility. Therefore, EPA must be clear that running new commercial power lines to any site is not EPA's intent given the practical, technical, and cost challenges this would cause at large scale implementation across the country.

2.5.2 Sufficient Volume and Quality of Grid Power

Equipment power requirements at oil and gas facilities are quite varied, ranging from instrumentation at a single well pad needing approximately 35 watts to operate all the way up to approximately 2,000 kilowatts at larger sites running more equipment on electrical power. The power demand required to operate equipment determines if single phase power (household) is adequate or if three phase power (industrial) is necessary. Single phase low volume power may be accessible in certain areas, but three phase industrial wattage levels may not be available. Furthermore, even with accessibility, there may not be sufficient levels to run a given site or field. Due to the challenges around the development of adequate power supply to remote locations and the temporary nature of some areas of oilfield demand, many sites are supplied by onsite generation through produced natural gas as a motive source or natural gas generators.

2.5.3 Right-of-Way Issues

The largest challenge to oil and gas operations having grid power is obtaining ROW access for power lines. On private lands, landowners may choose to never allow ROW, particularly on large ranches. On federal lands, the current lead time for installation is typically between 6 months up to 2 years. It should be noted that the longest lead times have been experienced on federal lands controlled under the Bureau of Land Management (BLM). Additionally, as the Administration pursues updates to other regulatory requirements, such as environmental reviews as proposed by the Council on Environmental Quality in the Phase 1 NEPA revisions, these challenges may be exacerbated by expanding requirements and protracted timelines. A Memorandum of Understanding (MOU) may be needed between the EPA and BLM and state land offices to expedite approval of ROW for grid power.

2.5.4 Even if logistically possible, it is unlikely to be cost effective to access off-site grid power to convert a site to non-emitting controllers.

Even without the foregoing concerns, the cost and timing to obtain grid access can be prohibitive when it is not readily accessible onsite. Since EPA did not include nor consider costs for installing new power lines in its cost benefit analysis, it is assumed EPA did not intend to require operators to run new commercial power lines in order meet proposed control requirements for pneumatic controllers. We support EPA in this approach, as this would not be cost-effective and would cause other environmental

[2] In some states, the utility provider can implement eminent domain, but production companies would not and do not have this authority. Other states, such as North Dakota, do not have eminent domain authority.

disbenefits (e.g., potential land disturbance) in pursuit of eliminating emissions from a small number of ancillary controllers.[3]

As a point of reference, experiences with API member companies suggest an average estimated cost of approximately $200,000 per mile for installing an electrical line to a facility where one does not already exist. When this additional cost is considered for 1 mile of new power line and all other EPA assumptions remain, retrofit of pneumatic controllers is not cost-effective for small and medium model plants.

2.6 Emission reductions may be offset where a diesel or natural gas generator would be necessary.

There are numerous situations where operators legally cannot obtain grid power, where solar may not be a feasible option, or where an operator may plan for connecting to grid power, but delays occur. In these situations, operators will utilize a non-emergency natural gas or diesel generator to power a compressor instrument air system as the only option to achieve a non-emitting standard. This scenario could be true at either new or existing locations. The tradeoff in this situation is between creation of criteria pollutants and CO_2 from generators when other power sources are not available versus venting of methane.

According to input from API members, a natural gas-fired generator of approximately 200-hp would be needed to support reliable operation of a large instrument air system without grid power. Emissions from a generator this size are estimated to be 1.94 tons per year (tpy) of NO_X, 3.88 tpy of CO, 1.36 tpy of VOC, 0.12 tpy of PM_{10}, 0.14 tpy CH4 and 730 tpy of CO_2[4]. The generator emissions will have environmental impacts and offset the VOC and methane emission reductions from use of non-emitting pneumatic controllers.

2.7 Solar Power Technology Challenges

2.7.1 The long-term reliability of solar-powered technologies is still being evaluated.

Non-natural gas-driven pneumatic controllers include solar powered electric controllers and solar powered instrument air applications. For remote sites without grid access, some operators are piloting solar arrays with battery storage to power an instrument air system for pneumatic controllers. We are unaware of any operators converting to solar powered electric controllers at this time. While the technology seems promising, many of these solar systems have not yet been proven reliable for all

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[3] On page 8-21 of EPA's Technical Support Document issued with this proposal, EPA states "Since this electrical supply is assumed to be on the site irrespective of the electronic controllers at the site, the costs of the power supply were not included in the analyses of emission reductions and costs for electronic controllers."

[4] Emissions were based on AP 42, Vol. I, 3:2, applicable NSPS JJJJ limits, and 40 CFR 98, Subpart C for a 201-bhp natural gas engine operating 8,760 hours per year. Methane estimated based on 40 CFR 98, Subpart C.

remote locations or facility designs and are not ready for deployment across the country at the large-scale EPA's proposed rules would require. In 2014, EPA stated "solar-powered controllers can replace continuous bleed controllers in certain applications but are not broadly applicable to all segments of the oil and natural gas industry."[5]

For many sites, a solar-powered pneumatic controller system presents significant design challenges to overcome, including, but not limited to, the following:

- Large-scale solar applications have not yet been tested in winter months when there is more cloud coverage, increased snow cover, and less sunlight in more northern locations (Colorado, North Dakota, Idaho, Wyoming, etc.). Evidence suggests that even during periods without direct radiation, substantive energy is supplied to solar panels through ground reflection and diffused radiation. However, without adequate field-testing, it is probable that supplemental power via natural gas or diesel -powered generators could be required during winter months and/or severe weather events. This is necessary to ensure a continuous power supply, and, thus, controlled operation. Interruptions within the control system pose safety risks to operators and can damage processing equipment, which could potentially lead to excess environmental emissions associated with equipment malfunctions.

- As discussed in Comment 2.7.3, at temperatures at or below -20°C (-4°F), solar battery capacity is decreased to 50%. This reduces the overall life of the solar battery, which impacts the overall reliability and lifespan of the system. Further, if low temperatures cause freezing, an interruption to power supply for the pneumatic controller system will occur.

- For many sites, the impact to photovoltaic performance based on the level of particulate accumulation on the solar panel(s) is not well documented. This is important for remote, unmanned sites as challenges associated with properly cleaning the panels are encountered. The decrease in energy loss due to particle accumulation greatly varies based on several factors including site location, surrounding soil type, dust characteristics, and other surrounding air pollution.[6] One study suggests that in the U.S. over a 3-month period, up to 4.7% solar capacity is lost due to particulate accumulation on solar panels.[7]

2.7.2 Many solar system packages in use do not feature turnkey solutions available for mass installation and implementation.

Technology provided by certain vendors was referenced in the Carbon Limits study published in 2016,[8] which EPA relied upon in its cost effectiveness analysis. Industry representatives reached out to at least

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[5] Oil and Natural Gas Sector Pneumatic Devices, Review Panel, USEPA, OAQPS, 2014: https://www.ourenergypolicy.org/wp-content/uploads/2014/04/epa-devices.pdf.
[6] Renewable and Sustainable Energy Reviews, Volume 59, June 2016, Pages 1307-1316. Renewable Power loss due to soiling on solar panel: a review, Mohammad Reza Maghami.
[7] Hottel, H, and Woertz, B. Performance of flat-plate solar-heat collectors. United States.
[8] Carbon Limits. *Zero emission technologies for pneumatic controllers in the USA.* August 2016

one of the vendors within the last six months to find out how much deployment there has been of these solar systems and electric controllers. The vendor indicated that in the past 10 years, they have conducted 200 retrofits and 300 new installs. Currently, the vendor projects it can only service approximately 200 installs per year.[9] Additionally, operators are already experiencing 6 to 12-month lead times for solar packages. The proposed rules will only exacerbate demand, increase costs, and increase pressure on the supply chain.

2.7.3 Additional technical challenges experienced with battery storage and capabilities prohibit use in some facility locations.

Remote oil and gas site applications for solar installations typically require up to 1,600 watt, 24 VDC capacity with a common battery type being an 8G8D gel cell (number of batteries required per application can range from 2 to more than 10). The exact number of solar sets is greatly variable based on site-specific requirements.[10] When sizing the solar system, in addition to site-specific requirements, the temperature profile of the site also impacts the type, number, and capable performance of batteries for solar packages. For example, the Deka 8G8D battery has an operating temperature range from -30°C (-22°F) to 50°C (122°F); however, the optimal operating range is above 0°C (32°F) because cold temperatures increase the internal resistance of a battery, thereby reducing capacity. The standard capacity rating of this example battery is based on each cell having an electrolyte temperature of 20ºC (68ºF).[11] At temperatures below the nominal rate, the battery's effective capacity is reduced, and the time to restore the battery to full charge is increased exponentially with decrease in temperature. Figure 1 displays the relationship between battery capacity and temperature for a Deka 8G8D solar battery; at -20°C (-4°F), battery capacity is decreased to 50%. Table 1 shows six states with significant oil and gas operations where temperatures fall in the range for reduced solar battery capacity during winter. Further, it is noted that the recent unprecedented winter storm in Texas (February 2021) saw a low temperature of -27° (-16°F).[12] Unfortunately, during severe weather days including snowstorms, solar panels are often not receiving sunlight and battery power is being used. Sufficient battery power at a high charge is needed for at least 7-10 days without sun. If the decreased sunlight lasts for too many days, batteries can freeze. Solar batteries in the oil field often freeze and stop functioning, particularly in areas where temperatures can drop to -40ºC (-40ºF).

On the other hand, extreme heat can also negatively affect battery performance and reliability. Though temperatures above 25ºC (77ºF) will slightly increase capacity, the potential of self-discharge and reduced battery life is increased. Further, as temperatures rise, any cycle life loss due to operating at higher temperatures is not recoverable. During extreme heat events, such as those experienced in Texas

[9] Joint Industry Work Group comments submitted to CDPHE https://drive.google.com/drive/folders/1yXOxLue7DqPFutsxbq6SeThCMhc5S7DU

[10] Example of solar installations at oil and gas sites: https://www.scadalink.com/products/remote-power/industrial-solar-panels/.

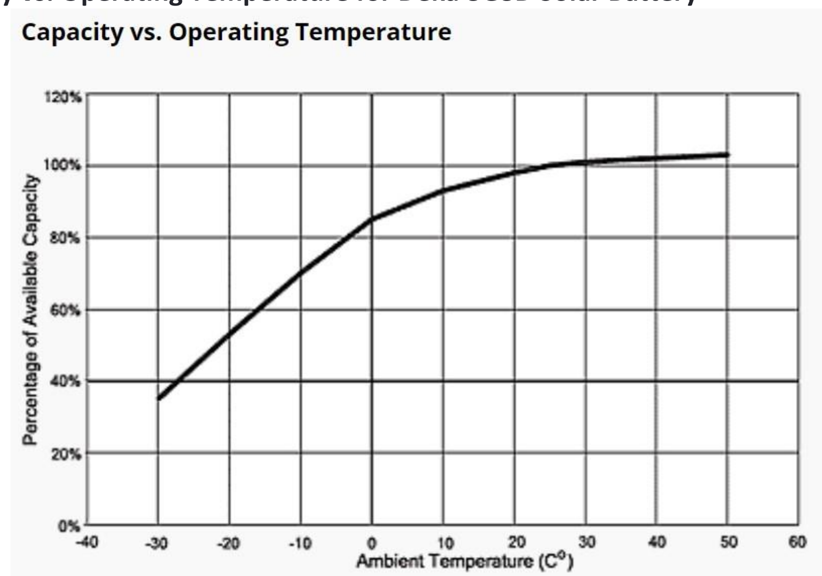
[11] Deka battery specifications: https://www.solarelectricsupply.com/solar-components/solar-batteries/gel-batteries/deka-8g8d-solar-batteries

[12] Feb. 2021 Texas Winter Storm Details: https://www.weather.gov/media/ewx/wxevents/ewx-20210218.pdf.

and Louisiana, overheating of the battery is possible. In this scenario, the battery lifespan can be shortened, or the battery can be completely damaged.

For nonessential equipment, losing power is not a concern. Pneumatic controllers are critical for safe operations. Due to the temperature profile of the key states in play, current solar battery performance may be too unstable for the operation of pneumatic controllers.

Figure 1. **Capacity vs. Operating Temperature for Deka 8G8D Solar Battery**



Source: https://www.solarelectricsupply.com/solar-components/solar-batteries/gel-batteries/deka-8g8d-solar-batteries

In addition to concerns related to temperature, the type and number of batteries required for remote industrial sites (e.g., gel lead acid batteries and absorbed glass mat (AGM) batteries) are on average higher in cost as compared to household solar panel systems.

Table 1. Winter Temperatures for some States with Oil and Gas Operations

State	Average Winter Temperature[13]		Record-Low Temperature[14]	
	°C	°F	°C	°F
North Dakota	-4	25	-51	-60
Texas	0	32	-30	-22
New Mexico	-16	3	-45	-49
Oklahoma	0	32	-35	-31
Colorado	-9	16	-52	-62
Alaska	-28	-18	-62	-80

[13] Average temperatures based on 30-year records, for average of December – February: https://www.usclimatedata.com/climate/united-states/us

[14] Record-low temperatures: https://ggweather.com/climate/extremes_us.htm.

2.8 Review of EPA's Cost Benefit Analysis for Converting Pneumatic Controllers to Non-Emitting

2.8.1 EPA based their model plant analysis on incorrect assumptions.

Based on blinded data collected from API member companies by a third-party, EPA has underestimated the costs and overestimated the benefits for converting pneumatic controllers to non-emitting. A summary of EPA cost assumptions is provided in Table 2.

Table 2. Summary of EPA Estimated Capital Cost Assumptions for Pneumatic Controllers

EPA Model Plant Reference	EPA Estimated Capital Cost for Grid Power Electric Controllers[a]	EPA Estimated Capital for Solar Power Electric Controllers[b]	EPA Estimated Capital Cost for Grid Power Electric Instrument Air System
Small (4 controllers)	$25,494	$28,171	Not estimated
Medium (8 controllers)	$45,889	$51,242	Not estimated
Large (20 controllers)	Not estimated	Not estimated	New: $95,602 Existing: $127,469

a. EPA costs included the costs of controllers ($4,000 each) and a control panel for grid connection ($4,000). EPA also included installation and engineering estimates based on 20% of equipment costs, which equated to $4,420 for small model plants and $8,040 for medium. EPA did not include any annual operating or maintenance costs within their assumptions.

b. For solar electric controllers, EPA costs included cost of electric controllers ($4,000 each), a control panel ($4,000), 140 W solar panel ($500), and 100 Amh batteries ($400 each). EPA also included installation and engineering estimates based on 20% of equipment costs, which equated to $4,000 and $7,200 for the small and medium model plants, respectively. EPA did not include any annual operating or maintenance costs within their assumptions.

The variation in the costs estimated by EPA with API member costs is centered on incorrect assumptions by EPA that companies will use grid power or solar based systems to power electric controllers. API members have converted natural gas driven pneumatic controllers to compressed instrument air systems powered by the grid (when accessible) or natural gas generators and are only in the initial phases of testing the reliability of solar based instrument air systems.

Costs associated with a typical instrument air system include a regenerative dryer, inlet filter, tank to store compressed air, insulated enclosure for the compressor and dryer, junction box, controllers for the compressor system, and voltage boosters. Additional costs for solar based systems would include higher cost gel or AGM batteries, sufficient number of batteries, and higher numbers of solar panels required in areas of less sunlight such as for Wyoming and North Dakota. Additional costs associated with the use of natural gas or diesel generators to power instrument air systems might also include monthly rental fees. All instrument air systems typically require annual maintenance at a cost of between $2000 and $4000 per year. Installation of non-emitting controllers also requires shutting-in the well or facility, an additional cost which does not appear to be accounted for in EPA's cost analysis. Cost estimates based on our blinded member survey are provided in Table 3.

Table 3. Average API Member Feedback regarding Capital Cost for Non-Emitting Technologies: Instrument Air Systems

Estimated Capital Costs for Various Sized Instrument Air Systems	Grid Power Instrument Air System[a,b]	Solar Power Instrument Air System	Natural Gas Generator Instrument Air System
Small to Medium	$51,000	Not estimated	$60,000
Medium to Large	$80,000		$110,000
Multi-Well Site, Central Production Facility or Compressor Station (>100 controllers)	$143,333	$250,000[c]	$207,250

a. Assumes the facility has existing grid power including a step-down transformer already in place and converts to an electric power instrument air system.
b. If grid access is not available, average costs to run a new power line is an additional $200,000 per mile.
c. This includes the cost of the solar panels, batteries and conversion to electric controllers and based on existing facility design with actual production values and local meteorological conditions.

Additionally, member experience has indicated that EPA's distinction between the small and medium model plant is incorrect when it comes to cost variation since a site with either 4 or 8 controllers would be considered a relatively small facility with minimal equipment. Some multi-well sites, central production facilities and compressor stations may contain 100-200 controllers. These larger facilities are typically the types of facilities that operators have been successful in retrofitting pneumatic controllers to non-emitting in a cost-effective manner by placing the investment of retrofit on the facilities with the most controllers. It is not economic and sometimes not feasible to convert pneumatic controllers to instrument air, particularly at older facilities with less wells and lower production. Retrofitting becomes even more challenging and uneconomic in instances where the wellhead is not co-located with the facility, as each remote wellhead would need its own power generation.

Additionally, some members have found that certain pneumatic controllers can be routed to an existing combustion device for a nominal investment. Like pneumatic pumps, there are challenges with this approach as not all existing locations may have an existing combustion device and not all types of controllers at a facility can be routed to an existing combustion device.

2.8.2 Emission Factors Applied for Intermittent Controllers

API appreciates EPA utilizing emission factors from API's *Field Measurement Study: Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas*.[15] However, we believe that the use of the average intermittent pneumatic device vent rate is incorrect in this application. In this same proposal EPA is proposing to include intermittent controllers within the monitoring framework by including them in the definition of fugitive component and considering their emissions in the determination of a site's potential methane emissions. Under this proposal, any intermittent device would be monitored routinely and repaired or replaced if malfunctioning, so the more appropriate emission factor that should be utilized is 0.28 scf whole gas/controller-hour and not the average emission factor of 9.2 scf whole gas/controller-hour as documented in API's 2021 GHG Compendium Table 6-15.[16] The average emission factor should only be used for controllers that are not routinely monitored as part of a proactive monitoring and repair program or where the monitoring status is unknown. The normal operation emission factor should be applied to controllers that are found to be operating normally as part of a proactive monitoring and repair program.

Emissions savings from this approach (i.e., the emission reduction benefit from fixing improperly functioning controllers) is currently already captured in EPA's cost-effective analysis for the proposed leak detection and repair (LDAR) requirements. This approach achieves nearly a similar level of emission reduction for much less investment by operators. This is especially true when converting a single existing high-bleed controller with a properly functioning intermittent controller that is part of a company's LDAR program. Furthermore, if an existing facility only contains properly functioning intermittent controllers confirmed through an LDAR program, then the cost effectiveness evaluation never becomes cost-effective for any amount of controllers even assuming EPA's own cost assumptions.

When we review EPA's cost effectiveness analysis, updating the intermittent controller emission rate to the properly functioning emission rate reduces the baseline emissions for each model plant significantly, which directly reduces the potential emission reductions. When coupled with the fact that EPA underrepresented the actual costs for conversion to non-emitting technologies, the cost-effectiveness for the proposal under NSPS OOOOb and EG OOOOc quickly becomes not cost-effective either for methane or VOC with or without savings.

In Attachment C, we evaluated the minimum number of controllers that would be cost effective to retrofit to an instrument air system powered by grid power or a natural gas generator, using the minimum costs listed in Table 3. The results indicate that for a facility containing low bleed controllers and properly functioning intermittent controllers, it would only be cost effective to retrofit if there were

[15] API's Field Measurement Study: Pneumatic Controllers EPA Stakeholder Workshop on Oil and Gas." Presented on November 7, 2019 in Pittsburg PA by Paul Tupper.
[16] https://www.api.org/~/media/Files/Policy/ESG/GHG/2021-API-GHG-Compendium-110921.pdf

at least 15 to 30 controllers, depending on the single/multi-pollutant, with or without savings approach, that EPA analyses.[17]

2.8.3 Retrofit of a single low bleed or intermittent controller is not cost-effective.

The cost effectiveness associated with converting a single low bleed or intermittent controller to a non-emitting controller using solar or electric power is summarized in Table 4. The results indicate it is not cost-effective to retrofit a single low bleed or intermittent controller. This analysis relied on controller system costs as provided in EPA's pneumatic controllers costs and emissions workbook for a small model plant. As we describe above, an API member survey suggests minimum costs are at least double the costs estimated by EPA for small model plants, which would best reflect the minimum costs associated with retrofitting a single controller. Based on this review, API suggests EPA exempt facilities from the non-emitting controller standard under NSPS OOOOb and EG OOOOc if there is only a single low bleed or intermittent controller present.

Table 4. Cost Effectiveness Estimates for Retrofitting a Single Low Bleed or Intermittent Controller

Retrofit Scenario as Outlined in EPA's Cost Effectiveness Analysis	Cost Effectiveness ($/ton) Without savings		Cost Effectiveness ($/ton) With Savings	
	VOC	Methane	VOC	Methane
Single low bleed to solar	$28,312	$7,870	$27,659	$7,689
Single low bleed to electric grid	$25,621	$7,122	$24,969	$6,941
Single properly functioning intermittent to solar[a]	$262,893	$73,078	$262,240	$72,896
Single properly functioning intermittent to grid[a]	$237,912	$66,134	$237,260	$65,952
Single unknown intermittent to solar	$8,001	$2,224	$7,349	$2,043
Single unknown intermittent grid	$7,241	$2,013	$6,588	$1,831

a. Emission factor for properly functioning pneumatic controller as referenced in Table 6-15 in the Compendium of Greenhouse Gas Emissions Methodologies for the Natural Gas and Oil Industry.[18]

[17] To estimate baseline emissions, we assumed a mix of controllers onsite of 30% low-bleed and 70% intermittent, which is consistent with the breakdown of controller types reported to EPA for the 2020 calendar year pursuant to 40 CFR Part 98, subpart W. EPA was incorrect to assume a high bleed pneumatic controller within their model plant analysis as the count of high bleed controllers is only 1% for the production segment and 3% for the gathering and boosting segment based on the 2020 Subpart W data (refer to Attachment A, Table C-1). We also applied the properly functioning emission factor from Table 6-15 of API's GHG Compendium based on the comments offered herein.

[18] https://www.api.org/~/media/Files/Policy/ESG/GHG/2021-API-GHG-Compendium-110921.pdf

2.9 EPA should not require a complete phaseout of properly functioning intermittent and low bleed natural gas driven pneumatic controllers at existing facilities.

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. Furthermore, existing well pads may have sizing constraints for the proper placement (due to safety and other permitting constraints) of control systems, compressors that must sit outside of classified areas, generators, or solar panels. For these reasons, the state regulations EPA cites in support of this proposal, including Colorado and the current proposed version of regulations pending in New Mexico[19], do not require all existing controllers to be retrofitted as EPA has proposed. Colorado's regulations, as well as the draft regulations pending in New Mexico, concluded this is unwarranted as controller retrofit is not cost-effective nor technically feasible for many facilities.

2.10 For EG OOOOc, retrofit to non-emitting controllers should be based on the availability of onsite grid power and a minimum number of gas-driven pneumatic controllers. Absent feasibility to retrofit, the use of continuous low bleed and intermittent natural gas controllers should be allowed and covered in an operator's existing LDAR monitoring program to monitor proper functioning.

For existing locations, API supports EPA's proposal to retrofit to non-emitting controllers, as we define in Comment 2.2, where the following criteria are met:

a) There are at least 15 controllers at the well site, central production facility, or compressor station; and

b) There is access to sufficient and reliable grid power onsite.

If the above criteria are not met, then any high-bleed natural gas driven controller should be replaced with a continuous low-bleed and/or with an intermittent controller and included within a company's LDAR monitoring program to monitor proper functioning. This approach is similar to and based on the rationale for EPA's proposed requirements for pneumatic controllers at sites in Alaska without grid access.

Refer to Comment 2.8 and Attachment C for API's determination of the minimum number of controllers required for retrofit to be cost effective.

[19] https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/Attachment-1-NMED-Proposed-Part-20.2.50-January-20-2022-Version.pdf

2.11 Adequate implementation time must be provided for pneumatic controller requirements under both NSPS OOOOb and EG OOOOc.

For modified sites (as outlined in Comment 2.4) and existing source retrofits, operators will need sufficient time for identifying devices for replacement or retrofit, designing and engineering systems, planning, budgeting, purchasing equipment, contracting labor, scheduling the work required and prioritizing equipment for retrofit. To retrofit a facility with instrument air, an engineer first verifies that adequate power is available and then applies for necessary permits, which takes approximately 60 days to acquire (if approved). 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 space to add necessary equipment. The gas lines, instruments, and tubing must be inspected to verify that they do not have any damage from extended use of wet gas. All lines, tubing and instruments with damage must be replaced. If there is not power at locations, generators will have to be set to power the air compressor. One retrofit project can take upwards of 4 months to complete from initial planning to full implementation.

As mentioned previously, there is a 3-year phase-in precedent that has been established for the oil and gas sector, which we believe is the minimum timing required for an appropriate phase-in of the pneumatic controller standard at existing locations. A more appropriate time period, given all of the existing sites in the U.S. and the implementation aspects outlined above, would be 5 years from the finalized rules/guidelines.

2.12 EPA must confirm that emergency shutdown valves or devices are not considered pneumatic devices.

In Section XI.C.1 of the preamble (86 FR 63179), EPA is soliciting comment on whether owners/operators believe that maintaining an exemption based on functional need similar to those finalized in NSPS OOOO and OOOOa is appropriate, and if so, why.

Emergency shutdown devices (ESDs) should remain exempt from the proposed pneumatic controller requirements. An ESD is designed to minimize consequences of emergency situations and will only emit in certain isolated circumstances, such as if a well must be shut in. A large change in pressure is required to actuate an ESD, which may not be deliverable in a sufficient time by a compressed air or electric controller. Furthermore, if power is lost, these devices must still be able to function. ESDs are rarely activated, and their emissions impact is minimal, but their functional need is necessary and critical to safe operations. We also note that both the current version of the proposed rule in New Mexico and finalized regulations in Colorado offer similar exemptions for ESDs.

2.13 The pneumatic controller requirements should be limited to stationary sources.

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. Connecting temporary controllers into the grid or routing to a combustion device requires significant engineering design, if these options are even available. Non-emitting requirements are not justified for short term controller usage related to a non-stationary source, and exemption of controllers on temporary equipment is consistent with state regulations proposed in New Mexico[20] and finalized in Colorado[21]. EPA should also make it clear that the requirements for pneumatic controllers are not applicable during drilling or completion.

3.0 APPENDIX K PROTOCOL FOR USE AT REFINERIES AND GAS PROCESSING PLANTS

It is API's understanding that the proposed Appendix K protocol was intended to streamline use of optical gas imaging (OGI) technology at refineries and other similar large process facilities such as gas processing plants, as an alternate to M21. In this regard, API supports EPA's development of Appendix K as the ability to use OGI technology provides flexibility and the potential to reduce equipment leak emissions at a lower cost than traditional methodologies.

However, API believes significant modifications to the proposed Appendix K are necessary before it could effectively be implemented for use across downstream oil and gas facilities, gas processing plants, or other process industries. API's recommended changes are intended to proactively address concerns that:

1) the proposed requirements will result in difficulty in finding and retaining adequate numbers of qualified senior OGI operators;
2) the monitoring, training and proposed QA/QC requirements are overly burdensome and will not lead to more effective leak detection; and
3) the ownership of various requirements, particularly the recordkeeping requirements, are unclear and unnecessarily burdensome.

API's recommended changes also aim to make the Appendix K requirements more straightforward and efficient. Our recommended modifications to Appendix K are detailed in Attachment A and a suggested redline of Appendix K is provided in Attachment B.

[20] https://www.env.nm.gov/opf/wp-content/uploads/sites/13/2022/01/Attachment-1-NMED-Proposed-Part-20.2.50-January-20-2022-Version.pdf
[21] https://drive.google.com/file/d/1JXzWUuPedxqHVCqiU6BdK3GJn_Z0x50X/view

4.0 FUGITIVE EMISSIONS AT WELL SITES AND COMPRESSOR STATIONS

4.1 Appendix K is inappropriate for use at production facilities, gathering and boosting compressor stations, and transmission compressor stations. OGI monitoring protocols for these facilities should continue to be based on NSPS OOOOa standards.

Appendix K is inappropriate and should not be required for upstream well sites, centralized production facilities, gathering and boosting compressor stations, and transmission compressor stations given. It is impractical for operators to implement the detailed and unnecessarily time-consuming requirements of Appendix K given the hundreds to thousands of well sites and compressor stations to monitor, the geographic dispersion of these facilities and the lack of on-site resources.

Key differences between production facilities and compressor stations versus refineries and gas plants include:

- **Upstream and midstream facilities are smaller, less complex, and have fewer regulated emission components.** A typical well pad size is up to a few acres versus up to thousands of acres for a refinery and well sites contain tens to hundreds of components versus tens of thousands of components at a refinery.

- **There are many more well sites and compressor stations.** There are hundreds of thousands of well sites and compressor stations in the U.S. versus approximately 129 refineries and approximately 500 gas plants.

- **Most new and existing well sites, centralized production facilities, and compressor stations are unmanned sites.** Additionally, these sites are often in remote locations**.** Refineries and gas plants have onsite LDAR personnel.

The following elements of Appendix K make it impractical to implement at upstream and midstream facilities other than gas plants.

- **Appendix K does not appear to support all potential OGI camera deployment platforms, such as drones or fixed continuous monitoring cameras, through its frequent use of the term "handheld".** Current NSPS OOOOa requirements allow a variety of OGI deployment platforms. EPA has also not demonstrated why a different OGI camera deployment would affect the ability of the OGI camera to detect and therefore require development of a separate operating envelope for each OGI camera deployment platform.
- **The lack of in-house personnel that qualify under the currently proposed Appendix K training requirements may force operators to rely on third-party contractors.** A reliance on third-party contractors could result in more emissions from delays in completing leak repairs, given a third-party contractor may not be trained or allowed by the operator to attempt an immediate leak repair. Under NSPS OOOOa programs, some companies' in-house OGI camera operators are allowed to make a first repair attempt upon leak detection.

- **The OGI camera performance specifications in Appendix K are different from those in NSPS OOOOa, reflecting the differences in the two types of sources these two methodologies address.** A comparison of these requirements is presented in the following table.

Appendix K	NSPS OOOOa
An OGI camera meeting the following specifications is required: The spectral range of infrared radiation measured by the OGI camera must overlap with a major absorption peak for the chemical target of interest, meaning the OGI camera must be sensitive with a response factor of at least 0.25 when compared to the response factor of propane for the majority of constituents (>75 percent) of the expected gaseous emissions composition.	Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.
An OGI camera meeting the following specifications is required: The OGI camera must be capable of detecting (or producing a detectable image of) methane emissions of 17 grams per hour (g/hr) and butane emissions of 18.5 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.	Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60g/hr from a quarter inch diameter orifice.

EPA has not demonstrated that these more stringent requirements are more effective at detecting leaks at well sites, centralized production facilities, and compressor stations. NSPS OOOOa camera specifications have been demonstrated as feasible by EPA testing and in the field. Existing cameras have not been tested and certified to meet the proposed Appendix K specifications. These more stringent Appendix K requirements will require retesting of existing OGI cameras and if the camera does not meet these requirements, require operators to purchase a new OGI camera, which is an additional cost not considered in EPA's cost analysis.

- **The "operating envelope" in Appendix K adds impractical requirements for viewing distance, delta-T, and wind speeds beyond NSPS OOOOa requirements.** NSPS OOOOa already requires procedures for *"determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained", "how the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions", and "determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold."*[22] The Appendix K operating envelope requirements are overly burdensome and may not result in

[22] 40 CFR 60.5397a(c)(7)

more effective OGI surveys; the current NSPS OOOOa requirements allow the flexibility to conduct effective OGI surveys under the variety of conditions encountered at well sites, centralized production facilities, and compressor stations.

- **The dwell time and break requirements in Appendix K are overly complicated, particularly for well sites, centralized production facilities, and compressor stations, where the density of fugitive emission components (number of components to view in each area) is less than for a refinery or gas plant.** These dwell time and break requirements would double or triple the time required for an OGI survey and have not been demonstrated to be more effective at detecting leaks. One company estimates that 40 or more hours would be needed to conduct an OGI survey of a single site following the Appendix K requirements. Unnecessarily long dwell times result in inefficient emission reductions and take time and resources away from other compliance activities with a greater environmental benefit. Furthermore, prescriptive dwell time is unnecessary and inefficient as an experienced camera operator will determine dwell time based on the circumstances that are occurring at the facility. Some components may require an extended dwell time, while other components may need less.

- **The 10-second video clips of leaks and tagging of leaking components required by Appendix K are overly burdensome to demonstrate compliance compared with the NSPS OOOOa requirement.** NSPS OOOOa requires that *"For each repair that cannot be made during the monitoring survey when the fugitive emissions are initially found, a digital photograph must be taken of that component, or the component must be tagged during the monitoring survey when the fugitives were initially found for identification purposes and subsequent repair. The digital photograph must include the date that the photograph was taken and must clearly identify the component by location within the site (e.g., the latitude and longitude of the component or by other descriptive landmarks visible in the picture)."*[23] EPA did not consider the additional cost of data storage for the 10-second video clips for a minimum of five years compared to a digital photograph. A digital photograph allows for identification of leaking components without tagging, which may not always be possible for elevated components or components in sour gas service due to safety considerations.

For these reasons noted above, API recommends that OGI requirements for new and existing well sites, centralized production facilities, and compressor stations be based on NSPS OOOOa requirements, not Appendix K.

4.2 EPA could strengthen standards finalized in NSPS OOOOa for using OGI in the production and transmission sectors and not apply the requirements in Appendix K.

As described in Comment 4.1, the provisions proposed in Appendix K are impractical for incorporation at upstream production facilities, gathering and boosting compressor stations, and transmission

[23] 40 CFR 60.5397a (h)(4)(ii)

compressor stations and would make the use of OGI for leak detection technically impractical and result in inefficient emissions reductions. Operators have been performing OGI surveys at new or modified well sites and compressor stations according to NSPS OOOOa requirements since September 2015. As proposed, Appendix K goes beyond the current NSPS OOOOa requirements concerning performance specifications, "operating envelope", survey time, and records for leaking components and is impractical for operators to implement given the hundreds to thousands of well sites and compressor stations to monitor and the geographic dispersion of these facilities. Therefore, API urges EPA to retain NSPS OOOOa standards in the proposed regulatory text for NSPS OOOOb and EG OOOOc rather than applying the requirements of Appendix K for these sectors.

The NSPS OOOOa standards for OGI surveys could be strengthened within the NSPS OOOOb and EG OOOOc language, especially with respect to training for OGI camera operators. To help address this concern, we offer the following suggested OGI requirements for the upstream, gathering and boosting, and transmission sectors based on current NSPS OOOOa language in 40 CFR 60.5397a(c)(iv):

> *What fugitive emissions VOC <u>and methane</u> standards apply to the affected facility which is the collection of fugitive emissions components at a well site or <u>centralized production facility</u> and the affected facility which is the collection of fugitive emissions components at a compressor station?*
>
> *[text omitted for brevity]*
>
> *(c) Fugitive emissions monitoring plans must include the elements specified in paragraphs (c)(1) through (8) of this section, at a minimum.*
>
> *[text omitted for brevity]*
>
> *(7) If you are using optical gas imaging, your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.*
>
> *[text omitted for brevity]*
>
> *(vi) Training and experience needed prior to performing surveys. <u>At a minimum, training and experience must include the elements in paragraphs (c)(7)(vi)(A) through (C) of this section.</u>*
>
> *<u>(A) Initial classroom or computer-based training including the items specified in paragraphs (c)(7)(v)(A)(1) through (8) of this section.</u>*
>
> *<u>(1) Key fundamental concepts of the optical gas imaging equipment technology, such as the types of images the equipment is capable of visualizing and the technology basis (theory) behind this capability.</u>*
>
> *<u>(2) Parameters that can affect image detection (e.g., wind speed, temperature, distance, background, and potential interferences).</u>*

(3) *Description of the components to be surveyed and example imagery of the various types of leaks that can be expected.*

(4) *Calibration, operating, and maintenance instructions for the optical gas imaging equipment used at the facility.*

(5) *Procedures for performing the monitoring survey according to the site monitoring plan, including the daily verification check; how to ensure the monitoring survey is performed only when the conditions in the field are within the established operating envelope; the number of angles a component or set of components should be imaged from; how long to dwell on the scene before changing the angle, distance, and/or focus; how to improve the background visualization; the procedure for ensuring that all regulated components are visualized; and documenting surveys.*

(6) *Recordkeeping requirements [assuming consistent with NSPS OOOOa streamlined improvements]*

(7) *Common mistakes and best practices.*

(8) *Discussion on the regulatory requirements related to leak detection that are relevant to the facility's optical gas imaging monitoring efforts.*

(B) *A minimum of 24 hours of surveys under the supervision of an experienced optical gas imaging equipment operator.*

(C) *Classroom or computer-based training refresher should be conducted no less than every three years. This refresher can be shorter in duration than the initial classroom or computer-based training but must cover all the salient points necessary to operate the equipment (e.g., performing surveys according to the monitoring plan, best practices, discussion of lessons learned throughout the year).*

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

4.3 With our recommended changes regarding Appendix K applicability, API supports EPA's co-proposal applicability thresholds and frequencies for OGI monitoring at well sites and supports quarterly monitoring at compressor stations.

For new and existing locations, EPA has proposed the following OGI monitoring frequencies based on the site's potential to emit (PTE) for methane as summarized below:

Site Methane PTE	Co-Proposal Monitoring Frequency
> 0 to <3 tpy	One time
≥ 3 to <8 tpy	Semi-annual
≥ 8 tpy	Quarterly

API is supportive of EPA's co-proposal thresholds and frequency for well sites and centralized production facilities contingent on our recommendations related to the prospective application of Appendix K to these types of facilities.

4.4 The baseline emission calculation for site PTE should be streamlined.

EPA's proposal that site methane PTE calculation updates be required "every time equipment is added to or removed from the site" is too broad and would be overly burdensome since operators would constantly track equipment and perform calculation updates for hundreds to thousands of sites.

As proposed, well site operators must recalculate baseline emissions (which are comprised of a combination of population-based components and controlled storage tank emissions) whenever equipment is added or removed from the site without regard to whether the change results in increased emissions. This appears to convert this fugitive emission requirement into a site-specific inventory requirement. As such, the proposal is inappropriate and has not been demonstrated to be necessary for implementation of the proposed requirement.

Recalculation of baseline emissions is not warranted where equipment is removed because equipment removal will result at best in fewer emissions and at worst in no emissions change. Further, requiring baseline emissions recalculation each time equipment is added to a well site will require onerous tracking of facility changes with little or no environmental benefit. For example, adding one fugitive component to a facility would have no meaningful or significant change to the well site's potential fugitive emissions, yet EPA proposes this change warrants recalculation of baseline emissions. Further, EPA's approach assumes, without basis, that any addition of equipment will result in increased potential fugitive emissions (and specifically in increased potential fugitive emissions with the potential to result in a different inspection frequency).

Under the proposal (i.e., requiring inspections for facilities with baseline emissions above 3 tpy), in very few instances would changes at the facility result in a change in monitoring frequency. Even under the co-proposal (with an additional tier between 3 and 8 tpy), there are limited circumstances when changes at the facility would result in a change in the frequency of inspections. Baseline emissions recalculation should be required only for the qualifying modification events based on the NSPS OOOOa definitions of modification for fugitive emission monitoring per 40 CFR 60.5365a(i)(3) and (i)(4).

For well sites in the most frequent inspection frequency tier, EPA should not require baseline emissions recalculation because no increase in emissions will result in more stringent requirements. If an operator elects to conduct a recalculation to determine if they can reduce inspection frequencies, then operators may elect to do so.

The following includes additional clarifying improvements for when and how to assess the site PTE calculation.

- There must be adequate time to perform initial site PTE calculations at both new and existing locations and to phase-in the initial monitoring survey. These are new calculation assessments and larger operators will have hundreds to thousands of calculations to manage, document, and plan for monitoring. Adequate time following a qualifying modification event must also be provided for updating the site PTE.

- Operators should have the ability to opt-in to quarterly monitoring without any requirement to calculate site methane PTE.

- For obtaining more accurate site emission estimates, operators should be able to use automation, measurement, or state approved emission factors in addition to the specified method described by EPA in this proposal.

- Since OGI detects leaks, but does not measure leaks, EPA must make it clear that sites with emissions less than 3 tpy conduct the one-time leak survey and not be required to reassess the emission evaluation unless there is a qualifying modification event.

- The PTE calculations should be limited to stationary sources. The addition or removal of temporary equipment should not require updated site methane PTE calculations.

- The site PTE calculation should only include controlled storage tanks.

4.5 EPA's cost analysis erroneously assumes operators would not purchase an OGI camera.

As API pointed out in our December 4, 2015 comment letter on proposed NSPS OOOOa[24], EPA continues to exclude the cost of an OGI camera within the cost benefit analysis and assumes operators will only rely on third-party contractors to perform OGI monitoring. This incorrect assumption must be re-evaluated by EPA. As we stated in 2015, API survey responses collected by a third-party ranged from $90,000-$100,000 for an OGI camera. A conservative assumption would be to include the costs for at least a single OGI camera. Most companies own and operate numerous cameras because it takes a team of LDAR technicians to implement and manage an OGI monitoring program across hundreds to thousands of sites.

We also note that EPA failed to consider any additional administrative burden associated with updated requirements described in the proposed Appendix K, which would be significant.

[24] API comments filed December 4, 2015 (EPA-HQ-OAR-2010-0505-4776)

4.6 The process for assessing the cause of equipment malfunctions and operational upsets should be streamlined with appropriate completion and reporting schedules.

EPA's proposal requires that an owner or operator must conduct a "root cause analysis" in the case of "a malfunction or operational upset of a control device or the equipment itself, where emissions are not expected to occur if the equipment is operating in compliance with the standards of the rule"(e.g., malfunctioning pneumatic controllers, unintentional gas carry through, or venting from covers and openings on controlled storage vessels) and also where an alternative screening event identifies a "large emissions event."

The specific term "root cause analysis" has other meanings in various regulations and in the oil and gas industry. Instead of using the term directly within NSPS OOOOb and EG OOOOc, we suggest the following description be used in its place as it targets what information and action should occur during the analysis:

> *"Identify the primary cause, and any other contributing cause(s), of a malfunction or operational upset of a control device or the equipment itself".*

We also suggest EPA streamline the recordkeeping and reporting of information related to the assessment.

4.7 Advanced leak detection technologies should be specified as an alternative BSER.

Using transparent and accepted models, alternate technologies can be demonstrated to be as effective as OGI and M21 in emission reductions and should be considered BSER. API supports EPA's inclusion of an option to utilize alternate methane detection technologies, but changes are needed to provide increased flexibility in their implementation. Discussed below are our suggestions to create a more workable framework.

4.7.1 EPA should create a functional and transparent framework for using alternate leak detection technologies.

API supports development of a framework that drives innovation and lowers the economic hurdles typically experienced with new technologies. Key considerations for such a framework include:

- **A minimum detection threshold of 10 kg/hr restricts operators' flexibility in selecting appropriate alternate technologies.** EPA's proposal arbitrarily sets the alternate technology minimum detection threshold to 10 kg/hr with a corresponding bimonthly survey frequency, coupled with an annual OGI survey. No supporting data are provided to demonstrate that this combination of technologies and frequencies is needed to achieve the desired emission reductions. Some operators are currently using alternate technologies with higher detection thresholds (e.g., 30 kg/hr), and the proposed framework should allow them the flexibility to continue the use of these technologies with an appropriate survey frequency. Conversely, the framework should also include lower detection thresholds and associated lower survey frequencies.

- **API supports the development of a matrix approach for alternate technologies.** For non-continuous technologies, the matrix should prescribe a minimum detection threshold based on a given survey frequency. The minimum detection threshold should be based on modeling (such as, but not limited to, FEAST or LDAR-Sim) that demonstrates that the alternate technology is expected to achieve the required emission reductions. This approach would not specify particular technologies or deployment platforms and would allow for easy use of future technologies so long as they meet the required minimum detection threshold. The proposed matrix could look like the following example.

Minimum Methane Detection Threshold (kg/hr)	**Survey Frequency (x per year)**
A	3
B	4
C	6

API members look forward to continued engagement with EPA on alternate leak detection technologies and in developing this matrix approach as EPA works towards the supplemental proposal. Our experience with modeling suggests monitoring frequency could be reduced to 4 surveys and one annual OGI inspection.

- **In the interest of transparency, any modeling results and information used to justify a proposed set of alternate technologies/detection thresholds and associated survey frequencies should be publicly available.** For others to evaluate and verify any proposals, it is necessary to have all relevant modeling information, including targeted control efficiencies, data inputs and assumptions. This transparency will be important both for any EPA modeling as well as modeling results submitted to EPA by other stakeholders.

- **The framework should support the use of multiple monitoring technologies for effective combinations of leak detection.** The framework should allow operators to implement one or more technologies to achieve the emission reduction goals. A combination of M21, OGI, and alternate technologies implemented at various frequencies can be as or more effective as a single technology at a given frequency. A matrix like the one above would allow operators to implement any technology that meets the minimum detection threshold for any given survey at the required frequency (i.e., a different technology could be used for each of the required surveys so long as it meets the minimum detection threshold). Separate matrices could also be developed based on a requirement to perform an annual OGI or M21 survey in addition to the screenings with alternate technologies. The frequency and detection threshold matrices would be supported by modeling.

- **The framework should also support the use of continuous monitoring technologies.** Continuous monitoring technologies can detect large leaks in real-time. API members see great promise in continuous/near-continuous methane monitoring technologies and encourage EPA to work with stakeholders to develop a framework that allows for usage of such technologies. Potential elements of the framework could include guidance on the content of an operator's continuous monitoring plan, including information such as types of sensors, modeling, placement of sensors, detection thresholds, downtime, networking/software, data fusion and management, follow-up procedures and QA/QC. To inform development of a proposed framework, EPA should consider hosting a multi-stakeholder workshop(s) prior to release of the formal regulatory text. API members look forward to working with EPA on pathways to developing monitoring programs.

- **A streamlined approval process should be included for future technologies that do not fit the existing framework.** API recognizes the challenges of writing regulations for a variety of alternate technologies and supports the inclusion of a streamlined approval process for alternate methane detection technologies that may not meet the prescribed framework but can be demonstrated to be as effective at reducing emissions. If such a technology is approved for one company, EPA should provide a pathway for other companies to implement this new technology under the same conditions approved, without the administrative burden of repeating an approval process that has already been reviewed and completed by EPA.

- **The proposed 14-day follow-up OGI survey should be focused on the highest emitting non-authorized sources and not be required for all emissions detected with alternate technologies.** The framework should limit follow-up OGI surveys to sites where the source of a persistent leak cannot be identified from the alternate technology screening data or other operational data. Not all emissions are actual persistent leaks. Where the alternate technology or operational data can identify the source of the detected emissions, the operator will evaluate whether the detected emissions represent an event that needs to be repaired or represent authorized emissions from the site. Where the source of an event can be identified by alternate technology or operational data, operators should have the option to not conduct a follow-up OGI survey and instead begin repair attempts. This option will focus operators' time and effort on repairing leaks instead of conducting follow-up OGI surveys to confirm information already provided by the alternate technology or other operational data.

  When required, follow-up OGI surveys should be prioritized for the sites with highest detected emissions; this approach will focus operators' time and effort on the repairs with the greatest environmental benefit. The framework should define clear thresholds for this prioritization of follow-up OGI surveys or repair attempts.

- **Timelines for a follow-up OGI survey or an initial repair attempt should be based on the date that final data (i.e., data that have undergone proper QA/QC procedures by the vendor) from the alternate technology screening are received.** Depending on the number of sites surveyed, final data from an alternate technology screening can be received days to weeks after the date that the actual survey is conducted. Compared to OGI surveys, alternate technology screenings allow operators to survey up to hundreds of sites more quickly and identify and repair large emission events. Although preliminary data from alternate technology screenings can be informative, the final processed data that has undergone proper QA/QC provides the operator more confidence in the results and contains more detail that allows the dataset to be actionable. The timeline to complete the follow-up survey or initial repair attempt should begin on the date that the final data report is received by the operator.

5.0 LEAK DETECTION AND REPAIR AT GAS PROCESSING PLANTS

API generally supports EPA's proposal for bimonthly OGI monitoring for equipment leaks at gas processing plants. We also support retention of NSPS VVa as an alternative monitoring option, as some facilities have compliance obligations through consent decrees or permits or are subject to state or local regulations that require the use of M21. In general, we also support the use of Appendix K for OGI monitoring at gas processing plants with appropriate changes as detailed further in Comment 3.0 and Attachments A and B.

We have additional suggestions to improve the described proposal and address implementation concerns as follows:

- **The proposed bi-monthly OGI monitoring requirements should also apply to closed vent systems and equipment designated with no detectable emissions.** This equipment should be treated like other fugitive emission components similar to the requirements option for quarterly M21 monitoring of pressure relief devices in NSPS OOOO and OOOOa (40 CFR 60.401a5401(b)). The increased frequency of bi-monthly OGI monitoring compared to an annual M21 survey should allow OGI to be as effective as M21 at detecting leaks from this equipment. Bi-monthly OGI monitoring would also decrease costs since a separate M21 program would not be required.
- **EPA should not remove the VOC concentration threshold from the proposed LDAR requirements and should instead propose a similar concentration threshold for methane.** EPA should retain the current 10.0 percent by weight threshold for VOC and add a 1.0 percent by weight threshold for methane. While EPA is correct that a VOC concentration threshold is not an appropriate threshold for determining whether LDAR for methane applies, EPA failed to realize that some streams at a gas processing plant have de minimis concentrations of VOC and methane (e.g., purity ethane, produced water, wastewater). Without appropriate concentration thresholds, equipment with no appreciable amounts of VOC or methane would be subject to LDAR requirements, which API does not believe was EPA's intent with this proposal. Minimum concentration thresholds are especially important if an owner or operator chooses to use M21 since tagging of components are required (along with accounting for and maintaining these tags); monitoring additional components with no appreciable amounts of VOC or methane adds costs and uses personnel resources with little environmental benefit.

6.0 STORAGE VESSELS

6.1 For completely new surface sites, API supports the proposed 6 tpy VOC threshold for a single storage vessel or tank battery.

API supports EPA's proposed 6 tpy VOC threshold for a single storage vessel or a tank battery affected facility at completely new well sites, centralized production facilities, and compressor stations. Although not discussed in the proposed rulemaking for NSPS OOOOb, API encourages EPA to retain the current alternate control standard in NSPS OOOOa to maintain the uncontrolled actual VOC emissions from a single storage vessel or a tank battery affected facility at less than 4 tpy VOC. In the preamble to the NSPS OOOO revisions dated April 12, 2013[25], EPA noted that removal of control at 4 tpy VOC will reduce emissions from burning more pilot gas than the waste gas being burned. Below are additional considerations regarding control requirements for a single storage vessel or tank battery:

- **As oil production declines, operators may need to replace the original storage vessel or tank battery combustion device with a smaller capacity device.** Applying the same threshold as a single storage vessel to a tank battery means that a control device will be required for a longer duration. This longer control duration and potential additional costs for a smaller replacement control device were not considered in EPA's cost analysis.

- **EPA should allow for an exemption from control requirements due to technical infeasibility if the control device would require supplemental fuel**. This type of exemption has been rationalized by state regulations for storage vessels and tank batteries, such as in Colorado, where there is an exemption from control requirements for tanks if use of a control device would be technically infeasible without supplemental fuel for pilot or other purposes. API recommends that EPA consider such an exemption for NSPS OOOOb and EG OOOOc. The regulatory text for the Colorado exemption is provided for consideration below.

> *Owners or operators of storage tanks for which the use of air pollution control equipment would be technically infeasible without supplemental fuel may apply to the Division for an exemption from the control requirements of Section II.C.1.c. Such request must include documentation demonstrating the infeasibility of the air pollution control equipment. The applicability of this exemption does not relieve owners or operators of compliance with the storage tank monitoring requirements of Section II.C.1.d.*

6.2 The proposed definition of tank battery should be based on manifolded tanks by liquid line.

EPA's proposed definition of a tank battery is overly complex given the objective of including a tank battery as a storage vessel affected facility. Based on the definition of a "storage tank" in Colorado

[25] Federal Register Vol. 78, No. 71, 22133-22134

Regulation 7, "manifolded by liquid line" is a simple and clear criterion for defining a group of storage vessels as a tank battery. The Colorado Air Quality Control Commission established a definition for a "storage tank" for Regulation 7 by expanding upon the definition of a storage vessel in NSPS OOOO and OOOOa to include storage vessels manifolded together by liquid line. The other criteria (e.g., physically adjacent, manifolded for vapor transfer) in EPA's proposed definition would cause potential confusion around applicability. We offer a suggested definition of a tank battery based on EPA's proposal language (86 FR 63178) as follows:

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

6.3 The proposed definition for a modification of a tank battery requires additional clarification.

The EPA is proposing to require that the owner or operator recalculate the potential VOC emissions when certain actions occur on an existing tank battery to determine if a modification has occurred. EPA's proposed definition for a modification of a storage vessel or tank battery is inconsistent with NSPS Subpart A and requires additional clarification. 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 should also clarify whether other individual storage vessels in an existing tank battery remain affected facilities under NSPS OOOO or NSPS OOOOa, as applicable, or become part of the modified tank battery under NSPS OOOOb.

API recommends the following changes:

> "The EPA is proposing that a single storage vessel or tank battery is modified *when physical or operational changes are made to the single storage vessel or tank battery that result in an increase in the potential methane or VOC emissions. Physical or operational changes ~~would be defined~~ include:*
>
> *(1) The addition of a storage vessel, to an existing tank battery;* <u>*or*</u>
>
> *(2) replacement of a storage vessel, such that the cumulative storage capacity of the existing tank battery increases.~~; and/or~~*
>
> *~~(3) an existing tank battery or single storage vessel that receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput (from actions such as refracturing a well or adding a new well that sends these liquids to the tank battery)."~~*

6.4 API generally supports EPA's proposal for existing storage tank batteries under EG OOOOc.

API generally supports EPA's proposal for 95 percent emission reduction for existing storage vessels and tank batteries with potential methane emissions of 20 tpy or more under EG OOOOc. That said,

- EPA should provide an exemption from control requirements due to technical infeasibility if the control device would require supplemental fuel.
- One additional consideration for existing storage vessels or tank batteries is the additional cost for control at sites in dry gas plays with produced water storage vessels or tank batteries only. Some of the produced water storage vessels are fiberglass tanks and would have to be replaced with steel tanks to support the installation of a closed vent system and control device due to backpressure. The additional cost for storage vessel replacement was not included in EPA's cost analysis. If capital costs to replace a storage vessels(s) are $20,000 or more this would result in a cost effectiveness of over $1,900 per ton of methane reduced for a combustion control device using EPA's own cost analysis.

6.5 API supports EPA's proposed alternative approach to specify within NSPS OOOOb and OOOOc that storage vessels at well sites and centralized production facilities are subject to requirements in those regulations instead of NSPS K, Ka, or Kb.

As EPA states in its proposal (86 FR 63184), "this alternative approach would eliminate the need for sources to determine if the storage vessel meets the exemption criteria specified in those subparts and instead focus on appropriate controls for the storage vessels based on the location and type of emissions likely present (e.g., flash emissions)." API believes that this approach provides a clearer path for determining regulatory applicability for storage vessels in the production segment. API notes that some storage vessels at production facilities store liquids that do not contain dissolved gases. For those tanks, facilities could still opt to control emissions using a floating roof, as is currently allowed under NSPS OOOOa (40 CFR 60.5395a(b)).

7.0 WELL LIQUIDS UNLOADING OPERATIONS

7.1 API generally supports a work practice standard built around the Best Management Practices approach described by EPA in this proposal.

API generally supports a work practice standard built around the Best Management Practices (BMP) approach described by EPA in this proposal. We support EPA in allowing flexibility for operators to manage and operate their wells based on the engineering needs of the well. As a point of clarification, we note that EPA's discussion of liquids unloading methods in the Technical Support Document to this proposal characterizes several techniques as non-venting techniques. Some of the solutions discussed may minimize emissions from unloading, but not fully eliminate them.

- **Contingent on clarification that these requirements are specific to liquids unloading of gas wells that vent emissions to atmosphere, we support EPA's proposed Option 2.** EPA should confirm that the liquids unloading requirements will apply to gas wells that vent emissions from liquids unloading to atmosphere only. Since EPA's process description in the Technical Support Document for liquids unloading mentions only gas wells, we believe that it was EPA's intent to limit the affected facility for liquids unloading to gas wells only.

- **EPA's proposal for Option 1 is not feasible**. As proposed, Option 1 would require operators to track all unloading events. This would include unloading events that are automated on artificial lift or pump jacks and even those that do not vent any emissions to the atmosphere. We do not support this approach as there is no environmental benefit associated with this Option and it would generate a significant amount of administrative burden.

- **Operators already report the number of liquids unloading events to EPA under the Greenhouse Gas Reporting Program.** In the proposal, EPA has described the reporting information for wells that utilize methods that vent to the atmosphere as including the number of liquids unloading events in an annual report, which is duplicative of other EPA reporting requirements.

- **EPA is correct in allowing flexibility for liquids unloading operations.** Well liquids unloading is a complex topic that has historically been difficult to address from a regulatory perspective. There are numerous misconceptions about why and how this activity is conducted. The technology options EPA describes in the proposal are designed to remove liquids from a well. Their function is not to reduce emissions resulting from gas that might be entrained in the liquids removed. For some situations a certain technique may reduce emissions, but the same option might increase emissions if applied on another well with differing characteristics. Therefore, we support EPA in providing criteria for consideration for inclusion in an operator's BMP, as listed in the proposal and provided below, but not dictating all specific practices:

  > *"BMPs would require operators to monitor manual liquids unloading events onsite and to follow procedures that minimize the need to vent emissions during an event. Such as:*
  >
  > - *having a person on-site during the liquids unloading event to expeditiously end the venting when the liquids have been removed,*
  > - *following specific steps that create a differential pressure to minimize the need to vent a well to unload liquids and reducing wellbore pressure as much as possible prior to opening to atmosphere via storage tank,*
  > - *unloading through the separator where feasible, and/or*
  > - *closing all well head vents to the atmosphere and return of the well to production as soon as practicable."*

- **EPA must clearly define liquids unloading within NSPS OOOOb.** Other well maintenance and workover activities may occur on a well. These activities are distinctly different, require different equipment and operation, and are reported differently in federal and state greenhouse gas inventories from well liquids unloading. To address this clarification, we offer the following definition for "Liquids Unloading":

    "Liquids Unloading" means the removal of accumulated liquids from the wellbore that reduce or stop natural gas production from natural gas wells. Routine well maintenance activities, including workovers, swabbing, coil tubing cleanouts, or any other activity that requires a rig or other machinery are not considered liquids unloading.

8.0 ASSOCIATED GAS VENTING FROM OIL WELLS

8.1 API supports elimination of venting from "each oil well that produces associated gas and does not route the gas to a sales line" with additional clarifications.

While EPA's proposal is overly broad in its description, API generally supports and recognizes the environmental benefit of the elimination of venting of associated gas from oil wells that do not currently route gas to a sales line (EPA's proposed option 2). If associated gas cannot feasibly and economically be recovered to a sales line, API supports capturing the gas for a beneficial use or flaring the gas such that 95% control efficiency is achieved.

8.1.1 Special considerations for handling associated gas at wildcat and delineation wells.

EPA did not allow provisions for wildcat or delineation wells in its proposal. By nature, these wells are typically located apart from other major oil developments including gathering infrastructure. Like provisions within NSPS OOOOa for well completions, EPA should allow special considerations for handling associated gas at these types of operations. Specifically, any associated gas initially generated from wildcat or delineation wells should be routed to a 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).

8.1.2 EPA correctly identified that access to a sales line does not equate to availability of a sales line.

API agrees that EPA correctly characterized scenarios *"when gas capture may not be feasible, such as when there is no gas gathering pipeline to tie into, the gas gathering pipeline may be at capacity, or a compressor station or gas processing plant downstream may be off-line, thus closing in the gas gathering pipeline."* (86 FR 63237).

To further elaborate, access to a sales pipeline is based on numerous criteria that can be out of the control of the well operator. A few challenges (including those above) have been summarized below for EPA's awareness and consideration:

- **Topography:** Mountains, rivers, lakes, etc. can limit a producer's ability to connect into a pipeline.

- **A contractual right to flow into the gas gathering system must be agreed to with the company that owns the gathering line**. In most cases, the company owning the well is different from the company that owns the gathering system. Therefore, contracts must be put in place to allow for flow to the gathering system. The company owning the gas gathering system must determine if the pipeline has the capacity to accept the additional well or wells being added and if the quality of gas meets their required specifications.[26]

- **Necessary permits and ROW must be obtained for the pipeline from the well site to the natural gas gathering system.** Permits and ROW are required for installation of the pipeline to connect to the natural gas gathering system. Sometimes obtaining the necessary ROW can be difficult and may require a court order. On certain federal lands, operators have been required by BLM in recent years to reroute proposed pipelines or to adjust installation techniques, which significantly delays the completion of gathering systems. On private lands, individual landowners may deny rights.

- **The natural gas must meet the specifications of the natural gas gathering line.** Contracts with the gathering company include specifications for entering the gas gathering line, such as allowable concentrations of inert gases such as carbon dioxide or nitrogen, and hydrogen sulfide. The natural gas gathering system owner ultimately controls when an operator can send gas to sales.

- **The natural gas gathering line must be operational.** Natural gas gathering lines can be temporarily down or unavailable for a multitude of reasons including, but not limited to, compressor maintenance or repair, line maintenance, line inspection, a gas plant being shut down, or temporary reductions in capacity. In some instances, a well will be connected to sales, but if a compressor station has an emergency upset, then the wells tied into the gathering system will not be able to send gas through the pipeline. These instances are often episodic, temporary, and not in the well operator's control.

Due to the various challenges described, EPA is correct in allowing the beneficial reuse of gas onsite or combusting the gas where accessing the pipeline is not available or technically feasible.

[26] Additionally, capacity issues could exist even in cases where the production company is also responsible for the gathering system.

8.2 EPA underestimated the cost of installing a flare in its cost benefit analysis, using a value significantly lower than EPA estimates for flares for other affected sources.

EPA must re-evaluate the cost effectiveness using more relevant cost information that is consistent with how flares are costed for other emission sources. Throughout the Technical Support Document for this proposed rule, EPA has assumed various costs with respect to installing a flare or other combustion device.

In review of EPA's cost evaluation data for associated gas from oil wells, EPA assumed that a flare would cost only $5,700. This value significantly underrepresents actual costs experienced by operators. 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. To obtain an average cost of $100,579 per flare, we reviewed the direct capital costs associated with calculation sheets issued by EPA[27] as listed in the following table:

EPA Flares Calc Sheet MP1 Small Flare	EPA Flares Calc Sheet MP2 Medium Flare	EPA Flares Calc Sheet MP-G Large Flare	EPA Flares Calc Sheet MP-H Largest Flare	EPA Estimated Average Costs for Various Sized Flares
$79,352	$84,761	$92,874	$145,328	**$100,579**

Note 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.

9.0 OTHER PROPOSED STANDARDS

9.1 Pneumatic Pumps

We generally support the pneumatic pump provisions as described in the proposal for NSPS OOOOb and EG OOOOc.

As noted in our December 4, 2015[28], comments on the proposed Subpart OOOOa[29], there are numerous implications for routing a piston pump to a control device or VRU and we continue to support EPA in excluding piston pumps from EG OOOOc.

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[27] https://www.regulations.gov/document/EPA-HQ-OAR-2021-0317-0039
[28] API comments filed December 4, 2015 (EPA-HQ-OAR-2010-0505-4776)
[29] https://www.regulations.gov/comment/EPA-HQ-OAR-2010-0505-6884

9.2 Reciprocating Compressors

9.2.1 The applicability of the compressor standards requires clarification.

EPA should clarify the applicability of compressor standards to well sites, as the proposal is unclear. The definition proposed for central production facility may extend applicability to compressors located at well sites, which have historically been exempt from the compressor standards. As EPA states they have not updated their cost analyses with new information with respect to well sites, we believe extending applicability to well sites is not EPA's intent.

EPA should also provide clarification that temporary compressors (i.e., those onsite for less than 12 months) are not subject to these provisions. Additionally, EPA should consider whether it is appropriate to establish applicability thresholds based on compressor size, stages, or gas throughput or exclude compressors used in specific applications (e.g., casing, injection, gas lift compressors).

9.2.2 EPA should provide additional flexibility for addressing rod packing leaks.

EPA should provide flexibility by allowing operators the option to change out rod packing based on hours of operation/fixed frequency, like the current requirements in NSPS OOOO and OOOOa, or to perform the newly proposed annual monitoring and replacement of rod packing if a leak is identified.

Another potential option to streamline the monitoring burden is to allow operators to screen for leaks during annual OGI assessments and only perform measurement of the rod packing if it is identified as leaking during the OGI screening. This option has been approved under the Greenhouse Gas Reporting Program for gas processing and transmission facilities under 40 CFR Part 98, subpart W.

9.2.3 Proposed packing leak threshold and logistical monitoring concerns.

EPA should re-evaluate the designated leak threshold of >2 scfm per cylinder, as it may not be appropriate for all applications. Appropriate leak thresholds vary based upon the individual compressor type, size, and operating conditions. Our preliminary review indicates the 2 scfm/cylinder threshold proposed by EPA is an extension of regulations finalized in California[30]. In review of supporting documentation provided by the California Air Resources Board, it seems this threshold for rod packing replacement is based on data from a single vendor's alarm set point.[31] Publicly available data from another compressor manufacturer[32,33] indicates "expected packing leakage for typical alarm points is between 1.7 and 3.4 scfm", and experience from some API members indicates some maintenance may

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[30] https://ww2.arb.ca.gov/resources/documents/oil-and-gas-regulation

[31] See pages 109 -110 of the Initial Restatement of Reasoning, May 31, 2016. https://ww2.arb.ca.gov/sites/default/files/barcu/regact/2016/oilandgas2016/oilgasisor.pdf

[32] https://www.arielcorp.com/company/newsroom/compressor-emissions-reduction-technology.html

[33]https://www.arielcorp.com/application_manual/Arieldb.htm#Packing_Leakage.htm?Highlight=packing%20leakage

be conducted up to a 4 scfm threshold per manufacturer recommendations. Therefore, a more comprehensive review of compressor manufacturer information is required for determining an appropriate threshold for rod packing replacement under NSPS OOOOb and EG OOOOc.

Clarification is also needed on how the annual monitoring standard is applied for certain packing vent configurations and systems. For example, if an operator uses a continuous meter on a rod packing vent, how would compliance be demonstrated against the annual measurement? How will replacing the packing due to a different reason/program affect the annual monitoring window? When packing vents are manifolded together, is the standard determined by multiplying the leak threshold by the number of cylinders?

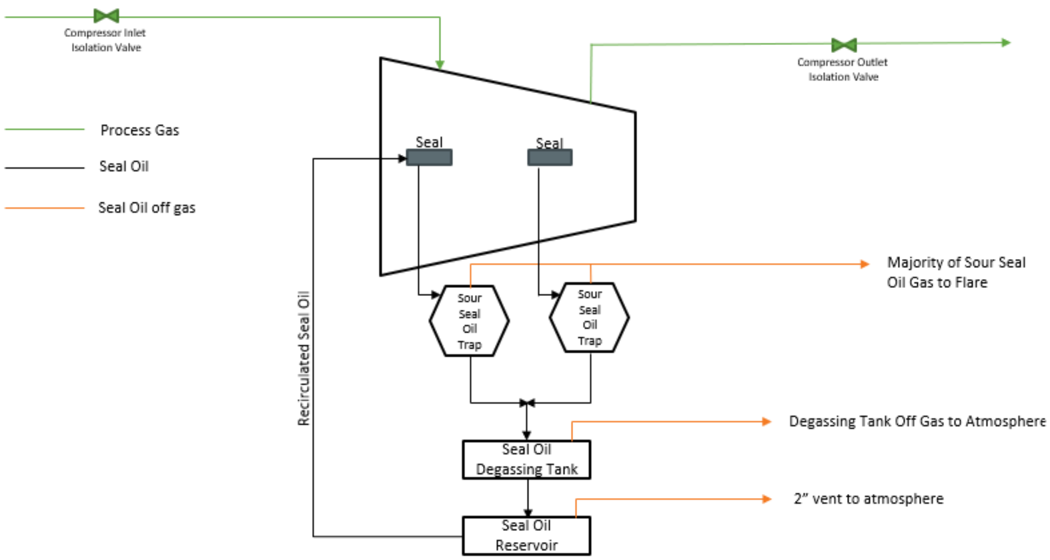
There are also practical considerations for how and when to conduct measurements. These types of concerns for implementation are well documented within subpart W for natural gas plants and transmission compressor stations. For example, the requirements in 40 CFR Part 98, Subpart W, only require rod packing measurements when a compressor is in operating mode at the time the measurement is set to occur (i.e., when the measurement team arrives onsite). Additionally, equipment modifications may be required to facilitate measurement of rod packing vents (e.g., adding an accessible port in vent piping), and adequate implementation time must be provided.

9.3 Wet Seal Centrifugal Compressors

9.3.1 Considerations for Compressors on the Alaskan North Slope

On the Alaska North Slope (ANS) there is not a market for natural gas sales. The majority of gas that is produced with the oil is separated and then compressed (using large wet seal compressors) to be reinjected back down hole for conservation and 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 the vast majority of the gas by volume then routes that gas to a flare. 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. The following figure depicts this process:



In 2010, EPA's Natural Gas Star program[34,35], 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. That level of emission control is equivalent to a dry gas seal system.

Since dry gas seal systems are not subject to these proposed rules (due to their low leak rate), and the ANS wet seal degassing system design has demonstrated equivalence to dry gas seal systems, wet seal degassing designs employing sour seal oil traps should also not be subject to the rule. The two systems are equivalent from a venting perspective and should receive similar treatment under the regulations.

10.0 OTHER COMMENTS

10.1 Orphan and Unplugged Wells

The information below is provided to address EPA's queries concerning idle/abandoned and orphaned wells.

10.1.1 EPA does not have authority under CAA § 111 to impose financial assurance requirements.

EPA explains that it "is soliciting comment for potential NSPS and EG to address issues with emissions from abandoned, or non-producing oil and natural gas wells that are not plugged or are plugged

[34] https://www.epa.gov/sites/production/files/2016-04/documents/smith.pdf
[35] https://www.epa.gov/sites/default/files/2016-06/documents/capturemethanefromcentrifugalcompressionsealoildegassing.pdf

ineffectively." 86 Fed. Reg. at 63240. Among other measures, EPA suggests that it "could require owners or operators to submit a closure plan describing when and how the well would be closed and to demonstrate whether the owner or operator has the financial capacity to continue to demonstrate compliance with the rules until the well is closed and to carry out any required closure procedures per the rule." *Id.* at 63241.

For the reasons discussed below, API believes 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. Should EPA decide to further address this issue in the upcoming supplemental proposal however, 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.

EPA and states have authority under the CAA to establish "standards of performance" applicable to affected facilities. *See* CAA §§ 111(b)(1)(B) and (d)(1). The term "standard of performance" is defined in CAA § 111(a)(1) to mean, in relevant part, "a standard for emissions of air pollutants" – *i.e.*, an emissions limitation or comparable requirement (such as an equipment or work practice standard). This is reinforced by the more broadly applicable CAA § 302(l) definition of "standard of performance," which defines that term to mean "a requirement of continuous emissions reduction." Neither of these definitions can reasonably be construed as authorizing EPA to issue financial assurance requirements for affected facilities.

In conjunction with the obligation of EPA and states to issue standards of performance, the Clean Air Act provides authority to establish corresponding compliance assurance measures, such as monitoring, recordkeeping, and reporting requirements. CAA § 114(a). However, a financial assurance requirement is fundamentally different in kind from such measures. Monitoring, recordkeeping, and reporting are designed to provide information necessary to determine applicability and demonstrate compliance with a standard of performance. In contrast, a financial assurance requirement is designed to make sure enough money is available to implement a standard of performance at some point in the future. Nowhere in the CAA is there express or implied authority for EPA to establish such a requirement.

Notably, in instances where Congress wants EPA to require financial assurance, authorization has been explicit. *See, e.g.,* 42 U.S.C. § 6924(a)(6) (Requiring EPA to establish rules for treatment, storage, and disposal facilities regulated under the Resource Conservation and Recovery Act to ensure "the maintenance of operation of such facilities and requiring such additional qualifications as to ownership, continuity of operation, training for personnel, and financial responsibility (including financial responsibility for corrective action) as may be necessary or desirable."). The absence of such an express provision in the Clean Air Act cannot be construed as a grant of authority.

10.1.2 Substantial progress on – and additional information concerning - idle/orphaned well clean up may be expected based on recent federal funding.

Passed as part of the Infrastructure and Investment Jobs Act of 2021, the REGROW Act provides funding to invest in the environment, and a skilled workforce. This includes $4.275 billion for orphaned well clean up on states and private lands, $400 million for orphaned well cleanup on public and tribal lands, and $32 million for related research, development, and implementation.[36] Any applications from states for these grant funds can help provide more concrete numbers. Additionally, any of these funds that are distributed as grants to state agencies may contain additional environmental and reporting obligations, which, when viewed in the proper context, may lend additional light to this issue. These recent developments further minimize the need or justification for EPA to expand its regulatory efforts on this topic to encompass orphan wells.

10.1.3 Further granularity on idle/orphaned wells was provided in December 2021, when the Intergovernmental Oil and Gas Compact Commission (IOGCC) released an update of its 2019 report on idle and orphaned wells to include 2019 – 2020 data. Because IOGCC's work is based on over 30 years of review, EPA should consider this information carefully before determining a course of action.

The Interstate Oil and Gas Compact Commission (IOGCC) is a multi-state government agency that promotes the conservation and efficient recovery of domestic oil and natural gas resources while protecting health, safety, and the environment. As an organization, IOGCC is committed to continuing to support the states and provinces in their efforts to continually improve their idle and orphan well programs and also to providing a forum for information-sharing of effective tools and strategies. IOGCC has also been included in the DOI MOU[37] for the recently enacted grant program referenced above.

Across decades of studying idle and orphaned wells, the IOGCC has published reports on the issue in 1992, 1996, 2000, 2008, and 2019.[38] A new report covering data from 2019 and 2020 was published in December 2021.[39] As these reports show, the IOGCC has been following this issue for 30 years. API encourages EPA and other agencies interested in regulations on this topic to review the report in detail.

The 2021 IOGCC report features survey responses from 32 IOGCC member and associate member states and five Canadian providences. It includes data from 2018 – 2020 and concerns the number of both idle and orphan wells, well plugging and site restoration costs, and remediation strategies (including regulatory tools and funding sources used to ensure idle wells are properly maintained).

The IOGCC report also provides helpful clarification of terminology, which is often misused in idle/orphan well conversations. We encourage EPA to align its terminology with the terminology used by IOGCC to reduce confusion:

- ***Idle Wells.*** The IOGCC defines idle wells as "wells that have not been plugged and are not producing, injecting, or otherwise being used for their intended purposes."[40] Similarly, they note that "[M]any idle wells have potential for oil or gas production or associated uses."[41] The future

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[36] REGROW Act Infrastructure and Investment Jobs Act of 2021, H.R. 3684, 117th Congress (2021).
[37] Orphan Well MOU (doi.gov)
[38] Interstate Oil and Gas Compact Commission (IOGCC), Idle and Orphan Oil and Gas Wells, (2019).
[39] Interstate Oil and Gas Compact Commission (IOGCC) Idle and Orphan Oil and Gas Wells, (2021).
[40] IOGCC *(*2021) at 2.
[41] *Id.*

outcome for an idled well could be that it is brought into production, plugged, or converted to an injection well for enhanced oil recovery or for disposal. Most regulatory agencies set a timeline and requirements (whether statutory, by rule, or by specific written approval) for how long a well may remain idled before it must be plugged. The total number of approved idle wells reported by the states as of December 31, 2020, is 231,287, which is 14 percent of the total number of documented wells that have been drilled but not plugged.[42] Notably, despite including 4 more states in the 2021 report, this is down over 20 percent from the IOGCC's 2019 figures, which featured "a total number of approved idle wells is 294,743, which is 15.6 percent of the total number of documented wells that have been drilled and not plugged."[43] In the three years covered by this report, operators plugged 62,463 wells in the states[44].

- ***Orphan Wells.*** The IOGCC defines orphan wells as "idle wells for which the operator is unknown or insolvent. Most states and provinces have inventories of documented orphan wells and prioritize orphan wells for plugging according to risk. As of December 31, 2020, the states reported a total of 92,198 documented orphan wells, and the provinces reported a total of 5,015 documented orphan wells. In the states, the number of documented orphan wells increased by 50 percent from 2018 to 2020, due primarily to the efforts of states to document these wells through investigation and verification of the status of wells and their operators. In the three-year period from 2018 through 2020, the states plugged 9,774 orphan wells and the provinces plugged 4,930. In total through 2020, the states have plugged over 78,000 orphan wells and the provinces almost 6,300."[45]

- ***Undocumented Wells.*** The IOGCC identified undocumented wells as a category for further work, noting that these are mostly a historical concern. Unverified estimates "do not convey a reliable picture of the actual number or the potential associated risk. The estimates are by their nature imprecise, and many undocumented wells may not constitute a significant risk to the environment or public health and safety."[46] It is important to understand that the lack of plugging documentation for these wells does not mean they were never plugged and the lack of the locations for such wells make any action or quantifications difficult. Thanks to modern record-keeping and regulation it is uncommon to be unable to identify the owner or operator a well. The majority of orphaned or undocumented wells occur as a result of development before the 1950s. For example, Pennsylvania is estimated to have the largest number of orphaned wells in the country, and the Pennsylvania Department of Environmental Protection explains, "Since the first commercial oil well was drilled in Pennsylvania in 1859, it is estimated that 300,000 oil and gas wells have been drilled in the state. Only since 1956 has Pennsylvania been permitting

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[42] *Id.*
[43] IOGCC *(*2019)at 5.
[44] IOGCC (2021) at 2.
[45] *Id.*
[46] Id at 3.

new drilling operations, and not until 1985 were oil and gas operators required to register old wells."[47]

10.1.4 EPA should not create duplicative and unnecessary regulations, which may conflict with specific rules promulgated by the states and BLM to address orphaned, idle, and abandoned wells.

Oversight for idle, orphan, and historical undocumented orphan wells is state-specific according to local regulatory programs, most of which include requirements for wells to remain idle and established prioritization systems for known orphaned wells. Additionally, most states already have funding mechanisms for plugging orphan wells, which are supported by industry taxes and fees. To avoid duplication or unintended consequences, the EPA should carefully examine these diverse programs and funding mechanisms prior to any additional regulatory work.

As an example of continuous improvement within the applicable states, over half of the states and provinces participating in the IOGCC survey reported improvements in their idle and orphan well programs between the IOGCC reports in 2008 and 2021. In 2019, the IOGCC noted that these included "process improvements in communication, collaboration, contracting, third-party plugging, compliance assurance, data systems, and bonding; implementation of program efficiencies; increases in staffing and funding; and application of Geographic Information System (GIS) and drone technologies. Through the decades, the states and provinces have made considerable progress in plugging orphan wells and reducing the likelihood of additional wells becoming orphaned. They have also continued to evaluate and adjust their financial assurance requirements and their plugging funds to ensure there will be funds available for well plugging and site restoration."[48]

The 2021 IOGCC report expanded its description of regulatory strategies used by the various states which include, "requirements, such as periodic mechanical integrity testing, that must be met for wells to remain idle beyond a specified time. These requirements may be set by statute, rule, or written approval. Most states and provinces also require financial assurance to provide money for plugging and restoration if the operator defaults. Financial assurance instruments include cash deposits, certificates of deposit, financial statements, irrevocable letters of credit, security interests, and surety or performance bonds. The types accepted and amounts required vary considerably among the states and provinces. The participating states all provide for single-well and blanket coverage, and the participating provinces provide for either single-well or blanket coverage, or both. The amounts may be uniform for all wells, or they may be based on the depth, location, type, or status of well or case-by-case evaluations. To supplement the funds provided through financial assurance instruments, most states and provinces have established funds dedicated to plugging orphan wells. Money for these funds comes primarily from taxes, fees, or other assessments on the oil and gas industry. Nineteen states and provinces reported on innovations and advancements in their idle and orphan well programs. Some

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[47] DEP Quote Pennsylvania Department of Environmental Protection, "The Well Plugging Program", available online at https://files.dep.state.pa.us/OilGas/BOGM/BOGMPortalFiles/AbandonedOrphanWells/WellPluggingProgram.pdf

[48] IOGCC (2019) at 21.

have added staff, improved their data management systems, and streamlined their contract management processes. Some have adopted new idle well requirements, such as requirements to provide additional financial assurance, demonstrate well integrity, justify keeping wells in idle status, or limit the percentage of wells an operator may hold in idle status. Increasingly, states and provinces are using Geographic Information Systems (GIS) and drone technologies to find orphan wells. They are also collaborating with operators and landowners to address idle and orphan wells and using grant programs, economic stimulus funds, and third-party partnerships for orphan well plugging and restoration."[49]

Activities on federal lands are regulated both by BLM regulations and by the state in which the operations are located. On federal lands, however, existing federal regulations obligate companies to bear the full costs of plugging and abandoning well sites.[50] In fact, companies cannot be released from liability until BLM determines they have properly done so. The April 2019 GAO report identified 296 orphaned wells which is a very small and manageable percentage of the 96,199 onshore federal wells.[51]

Beyond state and federal requirements, the oil and gas industry has developed relevant standards and practices which apply on both state and federal lands. These are relevant throughout a well's lifecycle; covering the safe conduct of drilling operations, standards for equipment and materials used during drilling and completion, and practices for well plugging and abandonment. In 2021, API's Recommended Practice (RP63),5- *Wellbore Plugging and Abandonment* provided specific guidance for the design, placement and verification of cement plugs used in wells that will be temporarily or permanently closed.[52] The standard also provides guidance for well remediation and verification of annular barriers, reinforcing groundwater protection and emissions retention. RP 65-3 joins several established API standards already in use for decades, including but not limited to API 51R, *Environmental Protection for Onshore Oil and Gas Production Operations and Leases* and API 65-2**,** *Isolating Potential Flow Zones During Well Construction***.** These are instructive templates for better understanding how industry practices work effectively across varying state and federal regulations.

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[49] IOGCC (2021) at 3.
[50] Ref federal regs See e.g., Bureau of Land Management, Onshore Order No. 2, 53 Fed. Reg. 223 (1988), available at https://www.blm.gov/sites/blm.gov/files/energy_onshoreorder2.pdf , and other onshore orders available at https://www.blm.gov/programs/energy-and-minerals/oil-and-gas/operations-and-production/onshore-orders
[51] Government Accountability Office, Report 19-615 Oil and Gas: Bureau of Land Management Should Address Risks from Insufficient Bonds to Repair Wells (2019) p. 14, citing Footnote 30 explaining that anecdotally BLM also indicated some of these 296 wells may no longer be orphaned.
[52] API RP-63 American Petroleum Institute, Recommended Practice 65-3, *Wellbore Plugging and Abandonment* (2021).

10.1.5 The emissions from non-producing oil and gas wells are comparatively small and may currently be overestimated within the datasets used by EPA's Inventories Program on Climate Change.

It is noteworthy that, under EPA's current methodology, the emissions from non-producing oil and gas wells constitute approximately 3% of all methane emissions from the energy sector – a number similar to rice cultivation.[53]

Definitional challenges across state agencies and data sets can lead to apples-to-oranges comparisons. For example, the distinction between "abandoned" and "abandoned and plugged" is considerable. Beyond the IOGCC definitions discussed above, the oil and gas industry often refer to any well that has been properly plugged as "abandoned and plugged." Similar to industry, EPA's definition of "abandoned" includes all wells that are no longer in production; however, these wells may or may not be plugged, and may or may not be considered "orphan" as defined by IOGCC This type of information is part of an ongoing dialogue with EPA's Climate Change Division concerning potential updates to the U.S. Greenhouse Gas Inventory (GHGI).

In the attached letter (Attachment D) dated November 16, 2021, to Ms. Melissa Weitz, API recommended the following clarifications and revisions to EPA's proposed methodology,[54] all of which underscore the challenge of creating an accurate count of wells across data systems:

- **Correcting assumptions concerning plugged vs. unplugged wells.** API requests from EPA a better explanation of how it estimated the number of 1.1 million historical abandoned wells, which are not captured in the Enverus database. Moreover, API maintains that EPA should not assume that all historical (pre-Enverus) wells are unplugged, without further supporting information. Looking at the restructured Enverus data at the end of 1975, which is the date EPA used to develop its estimate of historical (pre-Enverus) wells, indicates that 72% of the wells that would be classed as 'abandoned' by the criteria in Table 3 of the 2022 memo are shown as actually 'plugged and abandoned'.[55] Hence, EPA should not ignore the Enverus data in favor of unsupported assumptions.

- **Using the IOGCC Data.** API contends that an alternative estimate of historically abandoned wells could be based on data for 'undocumented orphan wells' provided in the 2019 report issued by the Interstate Oil & Gas Compact Commission (IOGCC).[56] According to the IOGCC 2019

[53] GHGI United States Environmental Protection Agency, Global Greenhouse Gas Inventory (2019).
[54] https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-abandoned-wells_sept-2021.pdf 2 IOGCC, 2019, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies.
[55] API's analysis of Enverus data does not validate the information in Table 3 of the 2022 Abandoned Wells Update Memo as representative of calendar year 2019. However, the counts in Table 3 are broadly similar to API's analysis of current date Enverus well counts. API requests that EPA should validate that their modified query of the Enverus database for 2019 counts is correct and provide this information to stakeholders in an updated Table 3 if changes are substantive.
[56]See https://iogcc.ok.gov/sites/g/files/gmc836/f/documents/2021/2020_03_04_updated_idle_and_orphan_oil_and_gas_wells_repo rt.pdf Updates Under Consideration – 2022 GHGI

report the total estimated number of undocumented orphan wells reported by the states is between 210,000 and 746,000 (as shown in Table 1. Total Idle and Orphan Wells: All Surveyed States and Provinces (2018)). Beyond the IOGCC information, API is not aware of alternative, high quality sources of data readily available to inform the count of abandoned wells or the split into plugged and unplugged categories.

- **Avoiding the double counting of dry wells.** API also asks EPA to provide greater insight into the process of restructuring of the Enverus data set and the treatment of dry wells. API notes that the designation of "Dry Wells" in the Enverus database indicate a production type rather than a status type and EPA's approach of considering all wells with no cumulative production as abandoned wells is likely leading to double counting of dry wells in the abandoned well category since they are embedded in the well status counts. Furthermore, EPA's assumption that dry wells are unplugged is neither consistent with the Enverus data nor State plugging requirements. Current Enverus data shows that 93% of dry holes are plugged. Texas requires the same plugging standards for dry holes as for idle production wells and other State requirements are believed to be similar. Moving forward, API recommends that EPA should continue to use the Enverus production type field, where available, to classify wells into gas vs. oil and should also use the Enverus P&A status for determining what dry holes are unplugged. API further recommends that EPA should continue to use the cumulative production coupled with the well status and production type information to determine the count of dry wells.

In that same letter dated November 21, 2021, API also highlighted some data considerations which may lead to an overestimation of emissions from those wells:

- ***Considering the impact of state regulations.*** Many of the largest producing states have regulations in place spelling out emissions, discharge or integrity requirements that must be met when a well is non-producing. API stipulates that the simple assignment of the 'unplugged' designation to all the status codes that are not 'Excluded' or 'Plugged and Abandoned' (P&A) overlooks the potential impacts of such regulations and is therefore inaccurate. Such regulations, even if not directly promulgated to control volatile emissions, have the potential for lower emission rates from wells that are subject to regulation when inactive.

- ***Using geographically correct emissions factors.*** API commented previously on Abandoned Wells emissions when EPA introduced the update for the 2018 GHGI. API noted that the studies conducted so far have limited geographical coverage and may not be nationally representative. To clarify, EPA uses the "entire U.S." emission factors from the Townsend-Small study, which include the much higher Eastern U.S. (Appalachian - Ohio) emission factors. They then use these same Eastern US factors from Townsend-Small coupled with emissions from Kang 2016 to develop emission factors for Appalachian basin abandoned wells. API recommends that EPA should use the more appropriate "western U.S." emission factors for abandoned wells outside of the Appalachian basin.

- ***Treating outliers appropriately.*** Additionally, the Townsend-Small Appalachia data are dominated by one well with emissions of 146 grams/hour that is about an order of magnitude higher than any other well, plugged or unplugged, in the Townsend-Small data. API contends that it is not appropriate to include this well in the emission factor for the entire US. Also, to date no emissions data are available from the state of Texas or many other major producing areas, calling into question the representativeness of the extrapolation of the results of the current studies to a nationwide estimate of the contribution of CH4 emissions from Abandoned Wells to the GHGI.

Similarly, it is important to note that other parts of the U.S. government are already considering the question of outliers or super-emitters. During a recent presentation to the Health Effects Institute, Natalie Pekney from the Department of Energy's National Energy Technology Lab (NETL) presented research showing that a comparatively small number of super-emitter wells are increasing the average emission rate.[57] This estimate was based on NETL's techniques for locating undocumented orphan wells by searching for magnetic signatures (using walking, helicopters, and drones) which have been validated through field work in Pennsylvania, Oklahoma, and Kentucky. EPA may benefit from looking at NETL's work in more detail, particularly since NETL intends to undertake more work in this area in Kentucky, New York, and Texas over the next few years.[58] This observation would be consistent with the states' established practice of prioritizing plugging and abandonment for individual wells; consequently, EPA may benefit from learning more about both NETL's research and considering how it may already be applied at the individual state level.

10.2 Pipeline "Pigging" Operations

As mentioned by EPA, there are several alternatives for reducing the various emissions from pigging operations. As each location has a different set of circumstances for its operations, the focus should be on reducing emissions volumes associated with pigging operations, allowing facilities to implement the necessary emission reduction alternatives that are most appropriate.

Some alternatives might be appropriate for broad application and other alternatives could require unreasonable cost and infrastructure modification for minimal emissions reductions. Existing programs and practices already implemented by operators also need to be considered. There is a distinction in the feasibility of capturing and controlling pigging emissions from those pig launchers and receivers co-located at a compressor station or gas plant as compared to remote launcher and receiver locations where supporting infrastructure (i.e., electrical power, line jumpers to low pressure pipelines, flares, etc.) does not exist.

The discussion below provides an example of how emissions from a pig launcher or receiver can vary widely.

Emissions from a pig launcher or pig receiver occur primarily from opening the isolated pig barrel (and often a short distance of piping connected to the pig barrel) to either insert or remove a pig. The emissions are from the natural gas inside this isolated area when the pig barrel is opened, which is

[57] Slide 8.Dr. Natalie Pekney, presentation on Health Effects Institute's webinar concerning "Abandoned and Orphaned Oil and Gas Wells," November 30, 2021.
[58] *Id.*

typically called a "blowdown." When a pig receiver is opened, there may be some residual liquids in the receiver, primarily from liquid falling off the pig itself. We note the volume of liquids in the receiver is unrelated to the amount of liquid a pig pushes down a pipeline. This limited amount of liquid in the receiver may have the potential for minimal flash emissions and perhaps volatilization.

Emissions from pig launchers and receivers vary widely based on several different, and sometimes interrelated factors: the diameter of the pig barrel and connecting midstream gathering pipeline; the length of the barrel or portion of the midstream gathering pipeline in between the pigging unit isolation valves; the pressure and composition of the gas within the unit; pig launching or receiving frequency; and the amount of liquids accumulation (applicable to receivers only). Consequently, frequency of pigging operations alone is not a good proxy for actual emissions as it is just one element that informs emissions. As a result, if one were to compare two pig launchers that are each used once per month, where the temperature is the same and the gas composition is the same, but the barrels have different diameters and lengths and different pressures, the actual emissions—calculated using the ideal gas law—from the two launchers would not be equal, potentially by a wide margin.

10.3 Tank Truck Loading Operations

Options typically used to reduce emissions from truck loading include routing emissions to a process (e.g., by installing a vapor recovery unit (VRU)) or to a combustion device. Many operators use a single, common VRU system or combustion device to control emissions from both hydrocarbon liquid transfers and storage tanks.

Practical, technical and safety issues that EPA should consider when evaluating potential truck loading emissions controls include the following:

- When loading emissions are to be routed to an existing combustion control device, substantial design evaluation work may be required to ensure that use of existing control devices is feasible, and if not, to design and install an additional or larger capacity combustion device.

- Some older facilities do not have the pad size to safely locate an additional combustor dedicated to loadout controls (if needed). Changes to the pad size require state agency and landowner approval, which may not be obtainable. Additionally, local governments and landowners may further prohibit operators expanding the footprint of a facility.

- If truck loadout vapors are routed through the storage tanks onsite prior to combustion, a new design analysis may be needed, which may generate costly modifications to low-producing sites (e.g., adding additional combustion control, larger combustors, change pipe sizing, etc.) in order to properly design the facility.

- Loadout truck drivers, who may not be familiar with truck loadout air emission equipment being used at these older low production facilities, will need additional training to safely use the new equipment. In many situations, the trucking company is a separate entity that may change over time from the producer.

- Older vintage buried and semi-buried tanks are not designed to work with truck loadout equipment.

- There are potential safety issues with the introduction of an oxygen rich vapor stream into atmospheric tanks that have minimal headspace. A higher oxygen percentage in the vapor mixture increases the risk of the vapor igniting and causing a fire or explosion. In these cases, the installation of an independent vapor control system may be required.

- Loading controls should not be required for sites where tanks are not required to be controlled.

- Lower producing facilities may have infrequent truck loadings based on production decline. EPA must evaluate the cost effectiveness of a reasonable threshold of crude oil/condensate prior to requiring any controls. Some states do not require loading controls if the number of loadouts is below a certain threshold or if the site routinely transfers liquids via a pipeline.

10.4 Opportunities to improve performance and minimize malfunctions on flares

EPA is soliciting comment on potentially proposing a change in the standards for wet seal centrifugal compressors, storage vessels, and pneumatic pumps that would require 98 percent reduction of methane and VOC emissions from these affected facilities. API does not support this change.

EPA also seeks comment on the appropriateness of applying standards from The Petroleum Refinery Sector Standards, 40 CFR part 63, subpart CC, amended in 2015 (80 FR 75178) to the oil and gas production, gathering and boosting, gas processing, or transmission and storage segments.

> *"The Petroleum Refinery Sector Standards, 40 CFR part 63, subpart CC, were amended in 2015 (80 FR 75178) to include a series of additional monitoring requirements that ensure flares achieve the required 98 percent control of organic compounds. Previously these flares had been subject to the flare requirements at 40 CFR 60.18 in the part 60 General Provisions. More recently, the updated flare requirements in NESHAP subpart CC have been applied to other source categories in the petrochemical industry, such as ethylene production facilities (40 CFR part 63, subpart YY), to ensure that flares in that source category also achieve the required 98 percent control of organic compounds. These monitoring requirements include continuous monitoring of waste gas flow, composition and/or net heating value of the vent gases being combusted in the flare, assist gas flow, and supplemental gas flow. The data from these monitored parameters are used to ensure the net heat value in the combustion zone is sufficient to achieve good combustion. The monitoring also includes prescriptive requirements for monitoring pilot flames, visible emissions, and maximum permitted velocity. Lastly, where fairly uniform, consistent waste gas compositions are sent to a flare, owners or operators can simplify the monitoring by taking grab samples in lieu of continuously monitoring waste gas composition, and in some instances, engineering calculations can be used to determine flow measurements."*

As we have provided feedback in the past[59], the refining sector is vastly different than oil and gas well sites, centralized production facilities, and compressor stations. The oil and natural gas production sector does not operate at steady state conditions. Equipment design must be tailored to the conditions and fluid compositions supplied by the reservoir. Oil and natural gas are located thousands of feet below the surface and must flow in two or three phases to the surface. The mixture is then separated in the two or three phase separator with steady pulses of produced water sent from the bottom of the separator to its storage vessel, hydrocarbon liquids off the middle to its storage vessel, and natural gas off the top of the separator to the gathering system.

As production declines in a gas well, management of wellbore liquids can mean that flow to the control device can vary from essentially zero to high flow rates and quickly back to zero rapidly and often. This highly variable, non-steady state flow mandates equipment to be sized much larger than ideal steady state conditions would dictate and makes flow measurement infeasible in these conditions.

Applying refinery-oriented requirements to upstream flares is not appropriate nor cost effective. Costs for Subpart CC controls at refineries are $1 million plus, with major ongoing costs. Costs would be much greater at upstream facilities without the necessary utilities and instrumentation resources. Nor is it clear that there is instrumentation available that would work reliably under the varying operating conditions. Additionally, adding natural gas to a flare to control the BTU content incurs capital costs as well as ongoing costs, and generates considerable greenhouse gases that would not otherwise be emitted.

We note that many states have moved to include some type of flare monitoring requirement within their local regulations or permitting processes. For example, Texas[60] requires that flares meet 40 CFR 60.18 requirements for minimum heating value and maximum tip velocity and have a continuous pilot flame (monitored by thermocouple or equivalent device) or an automatic ignition system.

10.5 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.

In footnote 2 of the proposal's Executive Summary section I.A. (86 FR 63113), EPA states:

> *"The EPA defines the Crude Oil and Natural Gas source category to mean (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.* ***For purposes of this proposed rulemaking, for crude oil, the EPA's focus is on operations from the***

[59] API's December 4, 2015, comments on the proposed Subpart OOOOa

[60] Texas Commission on Environmental Quality, *Control Device Requirements Charts for Oil and Gas Handling and Production Facilities* (February 2012). https://www.tceq.texas.gov/assets/public/permitting/air/NewSourceReview/oilgas/control-dev-reqch.pdf

> ***well to the point of custody transfer at a petroleum refinery*** *[emphasis added], 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''.*

Similarly, in the text in section III.B. (86 FR 63128), EPA states:

> *"The EPA regulates oil refineries as a separate source category; accordingly, as with the previous oil and gas NSPS rulemakings,* ***for purposes of this 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*** *[emphasis added], 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.''*

The implications of EPA's statements are unclear. 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 (for example, operations at a crude oil pipeline breakout terminal). We request that EPA clarify these statements in the supplemental proposal.

10.6 Use of the Social Cost of Methane in the EPA Regulatory Impact Analysis

10.6.1 API recognizes the importance of including the potential impacts of climate change in regulatory impact analyses.

When performing a benefit-cost analysis as part of a RIA, EPA is justified in applying an estimate of the value of the impacts of a regulation to reduce greenhouse gases. This is especially true in a regulation which has as its primary purpose the reduction of greenhouse gases. As noted in OMB Circular A-4, the monetization of as many impacts as possible, and especially those central to the regulation, is essential to a properly conduced benefit-cost analysis.[61] However, specific care must be taken when using the social cost of methane estimates (SC-CH_4) as an input to the RIA. Per the recommendations of the National Academies of Science, Engineering and Medicine (NASEM) in their 2017 review of the social cost of carbon estimates (SCC),[62] the social cost estimates should be presented with a full discussion of the uncertainties associated with the development and presentation of those estimates. This RIA describes some of the uncertainties well and includes a presentation of the frequency distributions used to generate the social cost estimates. However, there are some issues that have not been addressed, including the inability to use a consistent set of socioeconomic and emissions scenarios to generate both

[61] Office of Management and Budget, *Circular A-4* (September 17, 2003). https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/circulars/A4/a-4.pdf

[62] 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. https://doi.org/10.17226/24651

the social cost estimates and other benefits and costs associated with the regulation, and a consistent application of discount rates.

10.6.2 The interim social cost of methane estimates present a flawed approach to monetizing the impacts of climate change.

As noted in the 2021 Technical Supporting Document (2021 TSD), the interim social cost estimates represent the same methodological approach as the estimates generated prior to the disbanding of the Interagency Working Group (IWG) in 2017, and therefore rely on the same models and inputs from that effort.[63] API has previously commented on the social cost of greenhouse gas estimates (SC-GHG), including the SCC and the SC-CH_4 as developed by the IWG before 2017.[64] In these prior comment opportunities, API raised issues relating to the use of discounting, averaging across scenarios and Integrated Assessment Models (IAMs), the socio-economic and emission scenarios on which the modeling is built, and the handling of methane by the three IAMs on which the estimates rely. The conclusion upon reviewing these shortcomings of the previous and current interim SC-CH_4 estimates was "The SC-CH_4 (and SCC) estimates are highly uncertain and the causes of the uncertainty are not well understood."[65] While the NASEM study provided a better understanding of the uncertainties associated with the SCC and opportunities to improve the methodology of the SCC, the study did not extend to the SC-CH_4 nor did the IWG seek to improve the calculation of the SC-CH_4 in the publication of the interim values of 2021, as noted above.

10.6.3 Updates to the social cost estimates should be considered with robust stakeholder engagement.

The 2021 TSD notes that many of the same issues raised by API above are inputs that "need to be updated."[66] API and its members agree with this assessment; however, we have been concerned by the approach currently being taken by the IWG. As noted in API's comments to OMB regarding the Interim social cost estimates in June 2021, the actions taken thus far by the IWG do not reflect this administration's commitment to "public participation and an open exchange of ideas."[67] To date, there has been only one opportunity for stakeholder engagement in the social cost estimate development process initiated by E.O. 13990 – one that amounted to a request for information not an opportunity to comment on the work undertaken by the IWG. A recent brief filed by the Department of Justice suggests

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[63] Interagency Working Group on Social Cost of Greenhouse Gases, United States Government, *Technical Support Document: Social Cost of Carbon, Methane, and Nitrous Oxide: Interim Estimates under Executive Order 13990* (February 2021), page 5. https://www.whitehouse.gov/wp-content/uploads/2021/02/TechnicalSupportDocument_SocialCostofCarbonMethaneNitrousOxide.pdf

[64] *See* multi-association comments filed February 26, 2014 (OMB-2013-0007-0140); API comments filed December 4, 2015 (EPA-HQ-OAR-2010-0505-4776); and, API comments filed June 21, 2021 (OMB-2021-0006).

[65] API comments filed December 4, 2015 (EPA-HQ-OAR-2010-0505-4776).

[66] Interagency Working Group, 2021 TSD at 4.

[67] Executive Order 13563, *Improving Regulation and Regulatory Review* (January 28, 2011), at Sec. 1(a). https://www.whitehouse.gov/sites/whitehouse.gov/files/omb/inforeg/inforeg/eo12866/eo13563_01182011.pdf

that stakeholders will have an opportunity to comment on the revised social cost estimates that the IWG will propose in spring of 2022. In its brief, the DOJ stated that the IWG will "publish its proposed final estimates within the next two months," and that the public will be given the opportunity to comment on these proposed estimates.[68] Further, EPA has published a request for nominations to form a panel to provide an independent, scientific peer-review of the forthcoming estimates.[69] The indication of both an independent, expert peer-review and a public notice and comment period is a welcome development. API encourages the IWG to use the forthcoming opportunities to engage with stakeholders, address comments that are provided and seek further feedback. Along these lines, we encourage EPA to submit for public comment a list of questions EPA is considering to guide the expert peer-review along with the list of candidates as outlined in the EPA request for nominations.[70] These forthcoming engagements represent an opportunity for the IWG and EPA to improve their process.

Separately, the DOJ brief also indicated that the IWG has not yet submitted recommendations for the use of the social cost estimates across federal decision-making. API encourages the IWG and the White House to publish those recommendations, in full, for public comment.

API and its members look forward to the opportunities noted above to engage with the IWG and relevant agencies on the development and application of the social cost estimates. The provision of a well-developed estimate of the impacts of greenhouse gas emissions is key to regulations that seek to address such emissions. Failure to engage with stakeholders directly during the process or during a public comment period specifically to address the methodology of the estimates may jeopardize the durability of regulations dependent on this analysis. API encourages EPA, as a member of the IWG, to direct the IWG to follow through on the administration's commitment to public participation by opening the process and engaging directly with stakeholders.

Given the timeline set by this administration, and the updated timeline for the proposal of revised social cost estimates, it is likely that the IWG will have proposed a revised set of social cost estimates for stakeholder review and comment prior to EPA issuing a supplemental proposal or a final rulemaking for methane emissions from the oil and natural gas sector. API encourages EPA to complete a revised RIA including these new estimates and other factors as necessary before moving forward.

[68] Def. Supp. Br., 23, *La. v. Biden*, No. 2:21-cv-01074 (W.D. La. Jan. 21, 2022).

[69] On Tuesday, January 25th, EPA published a request for nominations of experts to act as reviewers of the proposed final estimates and the accompanying Technical Supporting Document (TSD). 87 Fed. Reg. 3801 (January 25, 2022)

[70] 87 Fed. Reg. 3803 (January 25, 2022)

11.0 OVERARCHING LEGAL ISSUES

11.1 The Proposal cannot set the new source trigger date under Subpart OOOOb because regulatory text is missing.

EPA proposes that the new source trigger date for Subpart OOOOb is November 15, 2021, the date the Proposal was published in the Federal Register. But here, publication of the Proposal cannot set the new source trigger date because the Proposal lacks proposed regulatory text, which is vital for fully assessing applicability and compliance. We appreciate EPA's promise to make proposed regulatory text available in an upcoming supplemental proposal. But that promise is not sufficient to set the new source trigger date at November 15, 2021.

Lack of proposed regulatory text creates an insurmountable practical problem. Affected facilities cannot know with certainty what regulatory requirements EPA has proposed and are thus unable to reasonably plan to comply with the final rule. Affected facilities can only surmise what the rule would require based on the description and explanation provided in the preamble. But affected facilities cannot know with sufficient clarity what would be required under the Proposal because they cannot see the part of the proposal that matters most – the regulatory text that would establish the binding legal obligations that would be imposed under the proposal.

As an initial matter, the lack of regulatory text means that the Proposal does not give fair notice to potentially affected facilities of what requirements they might be required to meet upon the effective date of the final rule. Fair notice is only achieved when EPA provides regulated entities with sufficient detail of what exactly will be required, which it has not done here.

Moreover, the publication date of the Proposal does not set the trigger date because it is not a proposed "regulation." CAA § 111(a)(2) defines "new source" to mean "any stationary source, the construction or modification of which is commenced after the publication of regulations (***or, if earlier, proposed regulations***) prescribing a standard of performance under this section which will be applicable to such source." CAA § 111(a)(2) (emphasis added). Thus, only a proposed "regulation" may set the new source trigger date.

The term "regulation" is not defined in the Clean Air Act. However, the term "regulation" is synonymous with the term "rule," which is defined in the Administrative Procedure Act to mean (in relevant part) "the whole or a part of an agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy or describing the organization, procedure, or practice requirements of an agency." 5 U.S.C. § 551(4).

Here, the 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 current preamble describes the type of regulatory requirements that EPA proposes to eventually promulgate, the preamble is 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 is absent here.

Thus, the Proposal cannot establish the new source trigger date because it does not include a proposed rule. The new source trigger date is tied to the date proposed regulatory text is published in the Federal Register.

As a last note, the CAA § 307(d) administrative rulemaking procedures do not expressly require a proposed rule to include proposed rule text. We do not opine on the question of whether a proposed rule subject to CAA § 307(d) provides adequate public notice and an opportunity to comment if it does not include or make available proposed rule text. But that issue is beside the point here because the new source trigger date is defined in CAA § 111(a)(2) and not in CAA § 307(d). So, even if the current proposal satisfies the procedural requirements of CAA § 307(d), it does not set the new source trigger date for the reasons explained above.

11.2 The CRA rescission of the 2020 Policy Rule does not extend to the legal rationale and policy positions used to justify the 2020 Policy Rule and does not endorse the legal and policy interpretations in the preceding 2012 and 2016 rules.

EPA explains that, as one of the three primary elements of the Proposal, it "is taking several related actions stemming from the joint resolution of Congress, adopted on June 30, 2021 under the Congressional Review Act (CRA), disapproving the EPA's final rule titled, 'Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review,' 85 FR 57018 (Sept. 14, 2020) ("2020 Policy Rule")." 86 Fed. Reg. at 63110. EPA further explains that:

> Under the CRA, the disapproved 2020 Policy Rule is "treated as though [it] had never taken effect." 5 U.S.C. 801(f). As a result, the preceding regulation, the 2016 NSPS OOOOa Rule, was automatically reinstated, and treated as though it had never been revised by the 2020 Policy Rule. Moreover, the CRA bars EPA from promulgating "a new rule that is substantially the same as" a disapproved rule. 5 U.S.C. 801(b)(2), for example, a rule that deregulates methane emissions from the production and processing sectors or deregulates the transmission and storage sector entirely.

Id. at 63151.

EPA further asserts that, in the legislative history of this CRA action, Congress "rejected the EPA's statutory interpretations of section 111 in the 2020 Policy Rule and endorsed the legal interpretations contained in the 2016 NSPS OOOOa Rule." *Id*. In other words, EPA asserts that the CRA action rescinded not just the 2020 Policy Rule, but also the "statutory interpretations" that stood behind the 2020 Policy Rule. EPA is incorrect.

The CRA applies to "rules." Most importantly, the CRA provides that "[a] ***rule*** shall not take effect (or continue), if the Congress enacts a joint resolution of disapproval" pursuant to CRA § 802. 5 U.S.C. § 801(b)(1) (emphasis added). Similarly, "[a] ***rule*** that does not take effect (or does not continue) … may not be reissued in substantially the same form." *Id*. at § 801(b)(2) (emphasis added). As explained above, the term "rule" is defined to mean "the whole or a part of an agency statement of general or particular applicability and future effect designed to implement, interpret, or prescribe law or policy or describing the organization, procedure, or practice requirements of an agency." 5 U.S.C. § 551(4). When EPA promulgates a final rule, the "rule" is the regulatory text (which imposes legal obligations or creates legal rights) and not the explanation and justification provided in the preamble to the rule. *See also* The Congressional Review Act (CRA): Frequently Asked Questions. Congressional Research Service (Nov. 12, 2021) at 18 (available at https://crsreports.congress.gov/product/pdf/R/R43992).

Thus, a rescission under CRA § 801(b)(1) and the prohibition under CRA § 801(b)(2) on issuing a rule in substantially the same form apply only to the relevant regulatory text and do not apply to EPA's explanation in the administrative record that accompanies the regulatory text. Contrary to EPA's suggestion, the legislative history of this particular CRA action cannot and does not change the plain meaning of the CRA statute. *See INS v. Cardoza-Fonseca*, 480 U.S. 421, 452-3 (1987) (J. Scalia, concurring in the judgment) ("Judges interpret laws rather than reconstruct legislators' intentions. Where the language of those laws is clear, we are not free to replace it with an unenacted legislative intent.").

As a final note, EPA's suggested approach would indiscriminately and inappropriately sweep away legal and policy positions stated in the record of the Policy Rule that are necessary for proper implementation of CAA § 111. For example, EPA explains in the preamble to the final Policy Rule that VOC "are not the type of air pollutant that, if subjected to a standard of performance for new sources, would trigger the application of CAA section 111(d)." 85 Fed. Reg. at 57040. Reversal of this uncontroversial interpretation would cause CAA § 111(d) to have a far broader scope than is reasonable or warranted under the plain text of the statute. Such an outcome is not required or supported by the CRA action.

11.3 API supports EPA's effort to improve and expand the methane emissions control program, however, the cost effectiveness threshold for methane used in the Proposal is not adequately justified.

EPA asserts flexibility as to how cost may be considered in determining BSER in the Proposal. 86 Fed. Reg. at 63154. But the Agency primarily relies on cost effectiveness thresholds expressed in dollars per ton of pollutant reduction. For methane, "EPA finds the cost-effectiveness threshold values up to $1,800/ton of methane reduction to be reasonable for controls that [it has] identified as BSER in this proposal." *Id*. at 63155.

EPA explains that "[u]nlike VOC, [it] does not have a long regulatory history to draw upon in assessing the cost effectiveness of controlling methane, as the 2016 NSPS OOOOa was the first national standard for reducing methane emissions." *Id*. In that 2016 rule, EPA "determined that methane cost-effectiveness values for the controls identified as BSER … range up to $2,185/ton of methane reduction." *Id*. "[B]ecause the cost-effectiveness estimates for the proposed standards in [the Proposal] are comparable to the cost-effectiveness values estimated for the controls that served as the basis (i.e., BSER) for the standards in the 2016 NSPS OOOOa, [EPA] consider[s] the proposed standards to also be cost effective and reasonable." *Id*.

Thus, the only justification the EPA presents for using a methane cost effectiveness threshold of $1,800/ton is that the Agency used a similar methane cost effectiveness threshold in the 2016 NSPS OOOOa rule. That "because we did it before" justification is wholly inadequate in API's view.

CAA § 111 requires that EPA develop a record to support its determination that the NSPS standards "represent[] the best balance of economic, environmental, and energy considerations." *Sierra Club v. Costle*, 657 F.2d 298, 330 (D.C. Cir. 1981). And an agency action is arbitrary and capricious if it does not "examine the relevant data and articulate a satisfactory explanation for its action including a rational connection between the facts found and the choice made." *Motor Vehicle Mfrs. Assn. v. State Farm*, 463 U.S. 29, 43 (1983) (internal punctuation and citations omitted). Here, EPA fails to meet these standards because it presents essentially no "relevant data" to support its proposed cost effectiveness threshold and, because of that, cannot and does not explain how the "relevant data" inform the choice of $1,800/ton.

For example, perhaps EPA believes that using values up to $2,185/ton in the 2016 rule provides evidence that values in this range are acceptable in the current proposal because the 2016 rule has been widely implemented across the affected industry. If this is what EPA believes, it should have said so. But it didn't.

Moreover, EPA has made no effort in the current rule to show why $2,185/ton is an appropriate touch stone, beyond simply asserting it to be true. That failure to present "relevant data" and to explain how those data inform the current proposal fundamentally undermines the proposed value of $1,800/ton. This is particularly important because, even under the Clean Air Act, two "wrongs" do not make a "right." *See New Jersey v. EPA*, 517 F. 3d 574, 583 ("[P]revious statutory violations cannot excuse the one now before the court.").

Lastly, EPA's factual determinations must be "supported by substantial evidence when considered on the record as a whole." *Coalition for Responsible Regulation v. EPA*, 684 F. 3d 102, 122 (D.C. Cir. 2012). The $1,800/ton threshold is supported by no evidence at all, much less substantial evidence.

11.4 API supports appropriate consideration and adequate protection of disadvantaged groups; however, EPA has not adequately explained how the proposed mandatory procedural requirements designed to foster "meaningful engagement" are authorized under the CAA.

EPA has made Environmental Justice a priority in developing the Proposal. For example, EPA made extensive outreach to disadvantaged and potentially overburdened populations and proactively sought to address their concerns in the proposal. EPA also included provisions in the Proposal that are at least partially designed to address Environmental Justice issues. For example, EPA explains that it provided for the use of "cutting edge" technologies in the rule, "alongside a rigorous fugitive emissions monitoring program that is based on traditional OGI technology." 86 Fed. Reg. at 63139. To address the concern of "addressing large emission sources faster," EPA proposes "more frequent monitoring at sites with more emissions." *Id*. And in response to concerns about health impacts, "EPA is proposing rigorous guidelines for pollution sources at existing facilities, methane standards for storage vessels, strengthened and expanded standards for pneumatic controllers, and standards for liquids unloading events that will further reduce emissions." *Id*.

API supports EPA's attention to potential Environmental Justice issues and agrees that the measures described above will significantly reduce emissions from this sector and should result in corresponding risk reductions for all potentially affected individuals. The natural gas and oil industry's top priorities are protecting the public 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 that may be disproportionately impacted.

While API supports EPA's goals, the Agency has not provided sufficient detail in the proposal to allow API to comment in a meaningful way. There is no proposed language to understand the impact of what the Agency intends to do, and other than broad statements that the requirements are authorized under CAA Sections 111(d) and 301(a)(2), no explanation of the substantive legal underpinnings of this concept. We look forward to the opportunity to offer further thoughts on this important topic in comments on the upcoming supplemental proposal.

11.5 Empowering local citizens by providing better access to relevant monitoring data is a worthy goal; however, EPA has not explained the legal basis for establishing a "community monitoring" program as described in the Proposal.

EPA presents 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 Fed. Reg. at 63177. "Specifically, the EPA seeks 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*.

API concurs with the importance of identifying and addressing large emissions events. Emissions from such events can be much greater than those from normal operations at a given facility and can result in material economic losses. API's overall support for the Proposal is grounded in a shared interest in seeking to reduce the incidence of such large emissions events.

Having said that, the community monitoring concept presented in the Proposal is novel. To our knowledge, 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. In concept, this provision would be akin to an LDAR program where an unaffiliated third party does the monitoring and the affected facility then has the legal obligation to address leaks identified by that monitoring. That is a truly new approach under CAA § 111 and the CAA as a whole.

Unfortunately, in describing the concept, EPA does not explain the legal basis for establishing such a provision. That, of course, is essential to understanding whether such a novel provision is legally viable.

We are concerned that EPA does not appear to have such authority. To begin, CAA § 111 calls for standards of performance to be established for emissions sources in regulated source categories. The statute unambiguously specifies that the Administrator shall establish standards of performance for new sources and the states should do so for existing sources. CAA §§ 111(b)(1)(B) and (d)(1). This scheme does not appear to leave room for regulatory obligations to be defined by the actions of third parties.

Moreover, EPA's authority to establish monitoring requirements is limited under CAA § 114 to just four entities: (1) any person who owns or operates any emissions source; (2) certain entities that manufacture emissions control or process equipment; (3) those with information "necessary for the purposes" of CAA § 114; and (4) those "subject to the requirements of this Act." CAA § 114(a)(1). The third parties EPA describes in the Proposal do not appear to fall into any of these four categories.

We note 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. Congress did not provide similar express language in CAA § 111 or elsewhere in the CAA authorizing the sort of citizen monitoring described in the Proposal. In this context, the absence of such language likely would be construed as a limitation on EPA's authority to allow such monitoring and would not be seen as an implicit delegation of authority from Congress to EPA.

If the Agency decides to actually propose a community monitoring provision in the forthcoming supplemental proposal, we encourage EPA to carefully consider these issues and clearly explain the purported legal basis for any such provision. In addition, EPA must clearly describe important details, such as how the Agency will quality assure third-party monitoring, what monitoring levels are actionable, and the mechanism by which monitoring data are determined to be actionable (*e.g.*, must affected facilities act on data submitted directly to them by third parties, or will EPA or a state regulatory agency determine when the need for action by affected facilities is triggered). And, of course, corresponding proposed regulatory text must be provided.

Lastly, these are complex issues that would benefit from further discussions between EPA, affected facilities, and other interested parties. We encourage EPA to conduct additional outreach on this issue prior to crafting the supplemental proposal. API would welcome the opportunity for a meeting.

11.6 Three proposed "modification" definitions are unlawful because they cover activities that are not a physical change or change in the method of operation of an affected facility that results in an emissions increase.

EPA proposes three equipment or activity-specific modification definitions that encompass actions that are not actually modifications. These must not be included in the final rule.

First, EPA proposes for centralized production facilities ("CPF") that a modification includes (among other things) when "a well sending production to an existing centralized production facility is modified." 86 Fed. Reg. at 63173. Second, EPA proposes that a single storage vessel or a tank battery is modified when (among other things) it "receives additional crude oil, condensate, intermediate hydrocarbons, or produced water throughput (from activities such as refracturing a well or adding a new well that sends these liquids to the tank battery)." *Id*. at 63178.

The word "modification" is defined in CAA § 111 to mean "any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted." CAA § 111(a)(3). Under this definition, two conditions must be satisfied for a modification to occur at a stationary source: (1) there must be a physical or operational change to the source; and (2) that change must result in an emissions increase or the emissions of a new pollutant.

The definitions described above share two flaws. First, a physical change or change in the method of operation is deemed to occur at a given CPF or tank/tank battery, even though no physical or operational change has occurred at that CPF or tank/tank battery. Under these definitions, the relevant physical or operational change occurs at a <u>different</u> affected facility. This plainly does not satisfy the statutory requirement that the modification of a given affected facility must entail a physical change or change in the method of operation at that same facility.

The second flaw with regard to these two definitions is that EPA has not demonstrated that these activities necessarily result in an emissions increase at the given CPF or tank/tank battery. For example, the fact that an upstream well is modified does not necessarily mean that a downstream CPF or tank/tank battery would have an actual emissions increase. More importantly, there is even less likelihood that the downstream operations would have a <u>regulatory</u> emissions increase, given that the Part 60 definition of "modification" requires an increase in the short-term potential to emit of an affected facility. 40 C.F.R. § 60.14(b).

Thus, the modification definitions for CPFs and tank/tank batteries are not consistent with the Act because: (1) they do not require a physical or operational change at the given affected facility; and (2) they presume an emissions increase where such an increase often would not occur.

A third proposed modification definition also is flawed, but for somewhat different reasons. For liquids unloading, EPA proposes that, because "each unloading event constitutes a physical or operational change to the well that has the potential to increase emissions, the EPA is proposing to determine each event of liquids unloading constitutes a modification that makes a well an affected facility subject to the NSPS." 86 Fed. Reg. at 63210. Here, the legal problem is that liquids unloading is necessary at many wells in order to achieve the production potential of the given resource. As such, liquids unloading is part of normal operations for the well and does not constitute a physical or operational change to that well. Moreover, because the regulatory definition of "modification" measures an emissions increase in terms of the short-term potential to emit of the affected facility, it cannot be said that liquids unloading results in an emissions increase.

API acknowledges that the D.C. Circuit has held that the definition of "modification" should be construed expansively. *New York v. EPA*, 443 F. 3d 880, 886-7 (D.C. Cir. 2006). But at the same time, the court recognized that even though the term "modification" is broad, it "cannot bring an activity that is never considered a 'physical change' in the ordinary usage within the ambit of NSR." *Id*. That is the case with liquids unloading.

11.7 EPA may not lawfully determine BSER to include technical infeasibility exceptions because BSER must be technically feasible.

EPA proposes two emissions standards that allow for "technical feasibility" exceptions. EPA proposes "a standard under NSPS OOOOb that requires owners or operators to perform liquids unloading with zero methane or VOC emissions." 86 Fed. Reg. at 63179. But "[i]n the event that it is technically infeasible or not safe to perform liquids unloading with zero emissions, the EPA is proposing to require that an owner or operator establish and follow BMPs to minimize methane and VOC emissions during liquids unloading events to the extent possible." *Id*.

EPA explains that "[a]n 'adequately demonstrated' system needs not be one that can achieve the standard 'at all times and under all circumstances.' Essex Chem., 486 F.2d at 433." *Id*. at 63213. "That said … the EPA recognizes that there may be reasons that a non-venting method is infeasible for a particular well, and the proposed rule would allow for the use of BMPs to reduce the emissions to the maximum extent possible." *Id*.

Similarly, EPA is "proposing a standard under NSPS OOOOb that requires owners or operators of oil wells to route associated gas to a sales line." *Id*. at 63183. "In the event that access to a sales line is not available, [EPA is] proposing that the gas can be used as an onsite fuel source, used for another useful purpose that a purchased fuel or raw material would serve, or routed to a flare or other control device that achieves at least 95 percent reduction in methane and VOC emissions." *Id*. The same standard is proposed for existing sources under Subpart OOOOc. *Id*.

These standards are based on determinations that non-emitting techniques constitute BSER for these sources. At the same time, EPA acknowledges that non-emitting techniques are not always feasible or safe. Alternative standards are provided to cover those situations.

API supports this approach 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.

Having said that, we are concerned that EPA has not asserted an adequate legal basis for taking this approach. In short, the fact that EPA needed to allow for technical infeasibility exceptions to the proposed non-emitting standards indicates that the non-emitting standards are not permissible under CAA § 111.

A "standard of performance" must reflect the degree of emissions limitation "achievable" through application of the best system of emissions reduction that EPA finds to be "adequately demonstrated." CAA § 111(a)(1). The proposed non-emitting standards do not meet this requirement for two reasons.

First, EPA has not demonstrated that techniques that eliminate emissions from liquids unloading events are "demonstrated in practice" for purposes of designating such techniques as BSER. It is true that non-emitting liquids unloading techniques can be used in <u>some</u> circumstances and that associated gas can be routed to a sales line in <u>some</u> situations. But the need to create exceptions under both standards shows that non-emitting techniques are not demonstrated in practice for the full range of regulated activities and circumstances. In effect, EPA seeks to avoid the obligation to show that non-emitting techniques are demonstrated in practice by creating exceptions for situations where non-emitting techniques are not demonstrated in practice.

Second, the proposed non-emitting standards of performance are legally questionable because they are not "achievable," as demonstrated by the need to establish exceptions to make the standard sufficiently practicable. But this bifurcated approach falls short because EPA puts the burden on affected facilities to prove to EPA that they qualify for the exceptions. In other words, the non-emitting standards are presumptively applicable. This approach incorrectly relieves EPA of the burden of promulgating achievable standards in the first instance and improperly defers infeasibility determinations to the time when the rule is implemented and enforced rather than when the rule is promulgated.

Essex Chemical does not support the Agency's approach here. As explained above, EPA points to *Essex Chemical* for the proposition that "[a]n 'adequately demonstrated' system needs not be one that can achieve the standard "at all times and under all circumstances." 86 Fed. Reg. at 63213. But the court was saying something much different than that. The following is a fuller excerpt from the opinion:

> It is the system which must be adequately demonstrated and the standard which must be achievable. This does not require that a sulfuric acid plant be currently in operation which can ***at all times and under all circumstances*** meet the standards; nor, however, does it allow the EPA to set the standards solely on the basis of its subjective understanding of the problem or "crystal ball inquiry."

Essex Chemical Corp. v. Ruckelshaus, 486 F. 2d 427, 433 (D.C. Cir. 1973) (emphasis added). The highlighted portion of this excerpt is what EPA cites. But, in context, it is clear that the court was not saying that BSER may be determined to be "adequately demonstrated" even though the corresponding standard of performance cannot be met "at all times and under all circumstances" by facilities that might become subject to that rule. Instead, the court was saying that EPA does not need to show that a "currently" existing facility (*i.e*., one in existence when EPA is formulating the rule) can meet the new standard of performance "at all times and under all circumstances."

In other words, the court confirmed that, given adequate justification, EPA may set technology-forcing standards of performance under CAA § 111 – standards that existing facilities would not necessarily be able to meet. This does not support EPA's proposal here to determine that non-emitting techniques are "adequately demonstrated" when it is clear that some significant number of potentially affected facilities will not be able to meet the non-emitting standards.

In sum, CAA § 111 requires BSER to be "adequately demonstrated" and standards of performance to be "achievable." We urge EPA in the upcoming supplemental proposal to provide a better explanation of how setting presumptively applicable non-emitting standards with a case-by-case "off ramp" satisfies these statutory requirements.

11.8 EPA should not define and impose practical enforceability requirements without first developing a coherent approach for all EPA programs.

EPA proposes "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 Fed. Reg. at 63201. "The 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*.

API believes that improving the clarity of the storage vessel applicability criteria is a worthwhile effort. However, the question of what constitutes an acceptable and effective "legally and practicably enforceable limit" goes well beyond the four corners of this regulation and has implications far beyond this narrow regulatory provision. This question is relevant across EPA's Clean Air Act stationary source programs: from major source permitting under NSR/PSD, to the Title V operating permit program, to all manner of federal and state emissions control programs (of which CAA § 111 is just one).

And, what constitutes an acceptable and effective "legally and practicably enforceable limit" has been an open question since the mid-1990s, when the prior "federal enforceability" requirement was remanded or vacated across EPA's programs. *See*, *National Mining Ass'n v. EPA*, 59 F. 3d 1351 (D. C. Cir. 1995); *Chemical Mfrs. Ass'n v. EPA*, 70 F. 3d 637 (D.C. Cir. 1995); *Clean Air Implementation Project v. EPA*, 1996 WL 393118 (1995). EPA announced its intent to conduct a comprehensive rulemaking to address the holdings in these cases, but has not yet taken action almost 30 years after the decisions were handed down. Memorandum from John S. Seitz to Regional Office Addressees, *Release of Interim Policy on Federal Enforceability of Limitations on Potential to Emit* (Jan 22, 1996) at 1.

With this as a backdrop, it is commendable for EPA to propose to clarify applicability of the storage vessel emissions standards by defining the term "legally and practicably enforceable limit." But this issue has implications that go far beyond the narrow confines of the storage vessel standard. Addressing it in a piecemeal, rule-by-rule fashion will ultimately cause confusion and potential inconsistency across the relevant programs. Further, it could inadvertently call into question existing permitting and regulatory regimes that do not specifically include the parameters proposed by EPA.

Moreover, affected facilities and states now have years of experience implementing the Subpart OOOO and OOOOa storage vessel standards, including substantial experience in crafting appropriate emissions limitations to govern applicability of these standards. Creating new mandatory procedural requirements is unnecessary, given that no systemic problem has emerged during this long implementation period. Such requirements would add to the cost and burden of implementing these standards without delivering any commensurate benefit.

Therefore, we suggest that EPA 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.

11.9 The requirement to use "non emitting" equipment or methods does not constitute a "zero emissions" numeric standard.

Numerous times in the Proposal EPA describes non-emitting equipment or work practice standards as "zero-emissions" standards. For example, for liquids unloading, EPA is "proposing a standard under NSPS OOOOb that requires owners or operators to perform liquids unloading with zero methane or VOC emissions."). 86 Fed. Reg. at 63179. For pneumatic controllers, EPA is "proposing a requirement that all controllers (continuous bleed and intermittent vent) in the production and natural gas transmission and storage segments must have a methane and VOC emission rate of zero.". *Id*. at 63202.

As a practical matter, the term "zero-emissions" is apt because the object of these proposed standards is to eliminate methane and VOC emissions from the affected facility. But as a legal matter, the term "zero-emissions" is imprecise and in error because these standards impose equipment or work practice obligations and do not impose a numeric emissions limitation of zero.

The legal distinction is important because a fully compliant pneumatic controller or liquids unloading event may still have incidental VOC and methane emissions. No piece of equipment or work practice is perfect – even if implemented according to best practices. Thus, the term "zero-emissions" expresses an idealized outcome that is belied by reality. A zero-emissions numeric standard would unreasonably cause incidental emissions to be a violation of the standard. EPA should correct its terminology in the Final Rule by stating that non-emitting control measures under this rule are work practices.

11.10 Emissions due to noncompliance should not be treated as "fugitive emissions" under the rule as proposed.

EPA proposes that the term "fugitive emissions component" should include "[c]ontrol devices, including flares, with emissions resulting from the device operating in a manner that is not in full compliance with any Federal rule, State rule, or permit." *Id*. at 63170. EPA asks for comment "on the use of the fugitive emissions survey to identify malfunctions and other large emission sources where the equipment is not operating in compliance with the underlying standards, including the proposed requirement to perform a root cause analysis and to take corrective action to mitigate and prevent future malfunctions." *Id*.

This proposal to expand the definition of "fugitive emissions component" to include emissions from control devices not operating in compliance with applicable rules must be clarified. All other equipment included in the definition of "fugitive emissions component" is not expected to leak (at least in any significant amount). As a result, when periodic leak monitoring is conducted, the goal is to discern the presence of a leak.

In contrast, even well operating emissions control devices and flares will have a permissible level of emissions. Thus, a periodic LDAR-type emissions survey should be expected to detect some amount of methane or VOC emissions.

That raises the question of what amount of emissions triggers the need for further action under the LDAR work practices, such as investigation and corrective action? The conceptual answer is an amount that represents noncompliance with applicable emissions or work practice standards. But the Proposal does not describe a mechanism for determining what level of emissions corresponds to compliant conditions and how to determine the increased amount that represents actionable noncompliance. In other words, the rule does not define what constitutes a "leak" for purposes of emissions control devices or flares. To be workable, EPA must include such details in the final rule.

We note that an operator cannot tell whether a control device is meeting its designed control or destruction efficiency (often 95 or 98 percent) through use of an OGI camera because an OGI camera does not quantify emissions. Thus, it is not possible to determine from an OGI survey whether a control device is operating at its required efficiencies. At best, an operator may be able to obtain information from an OGI camera that suggests further investigation may be necessary to determine whether a device is functioning as intended. But even this limited concept would pose significant questions as to how it might be implemented (*e.g.*, permissible emissions from a control device often vary considerably due to variable loading).

In addition, OGI and M21 are not even feasible for flares. EPA needs to explain how these methods would apply or, conversely, prescribe acceptable and workable alternative methods.

For these reasons, we urge the Agency in the upcoming supplemental proposal to explain further how the LDAR program would apply to emissions control devices and flares.

11.11 When work practice standards are fully implemented, emissions addressed by those standards cannot constitute a "violation."

EPA suggests in the Proposal that, when a leak is detected in a closed vent system during a fugitive emissions survey, "the emissions would be considered a potential violation of the no detectable emissions standard." *Id*. This is a variation of the "zero-emissions" issue described in Section 1.9, above. The "no detectable emissions standard" is a work practice standard. As with all other fugitive emissions components, detection of a leak (in this case, defined as detectable 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 with regard to fugitive emissions from closed vent systems. EPA must make it clear that a closed vent system remains in compliance when a leak is detected, as long as the associated work practices requiring investigation and repair are followed.

11.12 The proposal fails to explain and appropriately reconcile the applicability of Subparts OOOO, OOOOa, OOOOb, and OOOOc.

The Proposal is notably silent on the question of how to reconcile the applicability of the three new source NSPSs and the existing source program. The only clues as to EPA's thinking are the proposed applicability dates for the various subparts. For example, Table 1 lists the applicability dates for the new source standards (Subparts OOOO, OOOOa, and OOOOb) for new, modified or reconstructed sources that trigger these rules. 86 Fed. Reg. at 63117. Similarly, Table 1 indicates that the Subpart OOOOc existing source program applies to sources in existence on or before November 15, 2021. *Id*.

These dates alone do not adequately explain how EPA proposes to apply the rules. For example, the Proposal could be interpreted such that sources already subject to Subpart OOOO or OOOOa as of November 15, 2021 become "existing sources" on that date and will be subject to the Subpart OOOOc existing source program.

On the other hand, the Proposal could be interpreted such that sources already subject to Subpart OOOO or OOOOa as of November 15, 2021, are "new sources" under those rules and, therefore, they are not somehow transformed into "existing sources" on November 15, 2021.

This applicability issue is further clouded by the fact that Subpart OOOO applies only to VOCs, Subparts OOOOa and OOOOb apply to VOCs and GHGs, and Subpart OOOOc applies only to methane. Thus, if EPA intends that all sources for which construction, reconstruction, or modification is commenced prior to November 15, 2021, should become existing sources subject to Subpart OOOOc, that outcome would apply only for purposes of GHGs. To the extent such sources already were subject to Subpart OOOO or OOOOa, they would continue to be subject to those subparts for purposes of VOCs.

API has two recommendations on these issues. First, in the upcoming supplemental proposal containing proposed regulatory text, EPA must clearly propose how it intends to reconcile applicability of the various subparts. Applicability is a critical issue that cannot be left unaddressed or ambiguous.

Second, API recommends that there is only one permissible approach under CAA § 111, which would be comprised of two basic rules. First, a "new source" that is subject to Subpart OOOO, OOOOa, or OOOOb cannot be subject to the Subpart OOOOc existing source program. Second, and by extension, the Subpart OOOOc existing source program applies only to sources that were not subject to Subpart OOOO or OOOOa as of November 15, 2021[71] – i.e., the Subpart OOOOc existing source program applies only to sources that were not regulated by a relevant subpart as of November 15, 2021.

This outcome is required by two provisions in CAA § 111. First, the term "new source" is defined to mean "any stationary source, the construction or modification of which is commenced after the publication of regulation (or, if earlier, proposed regulation) prescribing a standard of performance under this section which will be applicable to such source." CAA § 111(a)(2). Because Subparts OOOO and OOOOa are "regulations" that "prescribed standards of performance" for affected facilities at "stationary sources," any affected facilities under Subparts OOOO or OOOOa unambiguously must be "new sources" under this definition. It does not matter that EPA has promulgated (and plans to promulgate) successive versions of the new source standard and it does not matter that the proposed Subpart OOOOc existing source program post-dates Subparts OOOO and OOOOa. Under the plain terms

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[71] API explains above that November 15, 2021, is not a permissible trigger date for Subparts OOOOb and OOOOc because the Proposal is not actually a proposed rule. API neither waives that position nor concedes that point here.

of the statutory definition of "new source," affected facilities under Subpart OOOO or OOOOa are "new sources.

Second, this point is driven home by CAA § 111(d), which states (in relevant part) that EPA shall prescribe regulations establishing a program for "any existing source … to which a standard of performance under this section would apply if such existing source were a new source." CAA § (d)(1)(A). This provision unambiguously directs that a CAA § 111(d) existing source program may apply only to an existing source that is not subject to a standard of performance for new sources. This necessarily follows from the definition of "new source."

11.13 EPA is not authorized to approve state existing source emissions limitations that were not derived using the required CAA § 111 standard-setting methods.

EPA proposes "[t]o the extent a State chooses to submit a plan that includes standards of performance that are more stringent than the requirements of the final EG, States have the authority to do so under CAA section 116, and the EPA has the authority to approve such plans and render them Federally enforceable if all applicable requirements are met. Union Electric Co. v. EPA, 427 U.S. 246, (1976)." 86 Fed. Reg. at 63251. EPA notes that "in the Affordable Clean Energy (ACE) rule, it previously took the position that Union Electric does not control the question of whether CAA section 111(d) State plans may be more stringent than Federal requirements." *Id*. But EPA "no longer takes this position." *Id*. "[B]ecause of the structural similarities between CAA sections 110 and 111(d), CAA section 116 as interpreted by Union Electric requires the EPA to approve CAA section 111(d) State plans that are more stringent than required by the EG if the plan is otherwise is compliance with all applicable requirements." *Id.* at 63251-2.

EPA further explains that "CAA sections 111(d) and 110 are structurally similar" and that "[r]equiring States to enact and enforce two sets of standards, one that is a federally approved CAA section 111(d) plan and one that is a stricter State plan, runs directly afoul of the court's holding that there is no basis for interpreting CAA section 116 in such manner." *Id.* at 63252. EPA concludes by noting that "its authority is constrained to approving measures which comport with applicable statutory and regulatory requirements. For example, CAA section 111(d) only contemplates that State plans include requirements for designated facilities, therefore the EPA believes it does not have the authority to approve and render federally enforceable measures on other entities." *Id*.

As EPA notes, the Agency took the diametrically opposite position in the ACE rule. "In response to commenters who contend the EPA does not have the authority to approve more stringent state plans," EPA agreed that the comments have merit. 84 Fed. Reg. 32520, 32559 (July 8, 2019). EPA provided a detailed explanation:

> [T]he Court's decision in Union Electric on its face does not apply to state plans under CAA section 111(d). The decision specifically evaluated whether the EPA has the authority to approve a SIP under section 110 that is more stringent than what is necessary to attain and maintain the NAAQS. The Court specifically looked to the requirements in CAA section 110(a)(2)(A) as part of its analysis, a provision that is wholly separate and distinct from CAA section 111(d). CAA section

> 110(a)(2)(A) requires SIPs to include any assortment of measures that may be necessary or appropriate to meet the ''applicable requirements'' of the CAA, which largely relate to the attainment and maintenance of the NAAQS. CAA section 111(d), by contrast, directs state plans to establish standards of performance for existing sources that reflect the degree of emission limitation achievable through the application of the BSER that EPA has determined is adequately demonstrated—and CAA section 111(d) expressly provides that it cannot be used to regulate NAAQS pollutants. Because the Court's holding was in the context of section 110 and not CAA section 111(d), the EPA believes that Union Electric does not control the question of whether CAA section 111(d) state plans may be more stringent than federal requirements.

Id. at 32560.

To sum up, two years ago EPA asserted that *Union Electric* <u>is not</u> applicable to state plans submitted under CAA § 111(d) because that case dealt only with state emissions standards adopted under CAA § 110. Moreover, emissions standards prescribed by CAA § 111 are materially different than state implementation plans submitted under CAA § 110. The former must be based on BSER, which is narrowly and precisely defined in the Act. The latter must be designed to satisfy minimum statutory requirements designed to achieve the broader air quality goals of attaining and maintaining compliance with the NAAQS.

Today, EPA proposes that *Union Electric* <u>is</u> applicable to state plans submitted under CAA § 111(d) because that provision and CAA § 110 are "structurally similar in that States must adopt and submit to the EPA plans which include requirements to meet the objectives of each respective section." 86 Fed. Reg. at 63252. EPA notes that the *Union Electric* court was concerned that, if more stringent state programs could not be approved under CAA § 110, then states that wanted to be more stringent would need to have two sets of regulations in place – a less stringent EPA-approved version and a more stringent state-only-enforceable version. The court concluded that such an approach was not warranted because it would impose "wasteful burdens" on EPA and the states. EPA argues that the same rationale equally applies to state CAA § 111(d) programs.

These opposing views are easily resolved by looking at what the court actually said in *Union Electric*. That case involved a 1972 Missouri state implementation plan ("SIP") for sulfur dioxide. *Union Electric Co. v. EPA*, 427 U.S. 246, 252 (1976). A local utility filed a challenge to that SIP claiming that the SIP was invalid because it imposed technologically and economically infeasible emissions control requirements. *Id*. at 253.

The court upheld the SIP on the grounds that "Congress intended claims of economic and technological infeasibility to be wholly foreign to the Administrator's consideration of a state implementation plan." *Id*. at 256. More specifically, the court interpreted "the 'as may be necessary' requirement of § 110(a)(2)(B) to demand only that the implementation plan submitted by the State meet the 'minimum conditions' of the [1970 CAA] Amendments." *Id*. at 264. "Beyond that, if a State makes the legislative determination that it desires a particular air quality by a certain date and that it is willing to force technology to attain it – or lose a certain industry if attainment is not possible – such a determination is fully consistent with the structure and purpose of the Amendments, and § 110(a)(2)(B) provides no basis for the EPA Administrator to object to the determination on the ground of infeasibility." *Id*. at 265.

Thus, the court expressly held (as EPA observed in 2019) that CAA § 110(a)(2)(B) allows states to adopt more stringent programs than minimally required by the Act. In that context, its observation that CAA § 116 should not be read as only authorizing more stringent state-only emissions control programs, *id.* at 264, is limited to programs such as CAA § 110 that, in the first instance, allow states to adopt more stringent measures than minimally required under the Act.

Here, CAA § 111(d) unambiguously requires state existing source programs to prescribe "a standard of performance," which is defined to mean "a standard for emissions of air pollutants which reflects the degree of emissions limitation achievable through the application of the best system of emissions reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." CAA §§ 111(d)(1)(A) and 111(a)(1). There is no room for states to do anything more than prescribe standards of performance that reflect BSER. Thus, in sharp contrast to CAA § 110, CAA § 111(d) does not prescribe "minimum conditions" that may be exceeded by the states. Instead, CAA § 111(d) requires standards of performance that must reflect a BSER determination that is based, among other things, on consideration of costs and feasibility. If proposed state standards of performance do not meet these requirements, they must be rejected by EPA.

Therefore, "structural similarities" between CAA §§ 110 and 111 do not provide an adequate basis for EPA's proposal that it may approve state standards of performance that are more stringent than required by CAA § 111(d). Such an approach unreasonably and unlawfully ignores the significant substantive differences between CAA §§ 110 and 111 and would violate the unambiguous requirement that state § 111(d) standards of performance must reflect BSER.

To be clear, API supports the coordination and consolidation of federal and state emissions control requirements for the oil and gas sector. Ideally, only one set of standards would apply – state devised and administered emissions control programs that simultaneously satisfy CAA § 111 requirements and address any unique state priorities and objectives. We believe there is sufficient latitude under CAA § 111(d) to allow for EPA approval of state programs in most cases because, in our experience, state programs are typically grounded in principles that would satisfy CAA § 111 standard setting criteria.

But it is at least theoretically possible that a state would seek to impose emissions control obligations that go so far beyond CAA § 111 principles that such obligations cannot be squared with the federal CAA requirements. In such cases, states have authority under CAA § 116 to implement their programs as a matter of state law. But there is no authority under CAA § 111 or 116 for EPA to federalize such state programs.

Attachment A

API Comments on Prepublication Draft Appendix K – Protocol for Using Optical Gas Imaging to Detect Volatile Organic Compound and Greenhouse Gas Leaks

API Comments on Prepublication Draft Appendix K – Protocol for Using Optical Gas Imaging to Detect Volatile Organic Compound and Greenhouse Gas Leaks[1]

I. General Comments on Proposed Appendix K Draft

1. API supports use of Optical Gas Imaging (OGI) technology because of its potential to reduce equipment leak emissions at a lower cost than through use of traditional methodologies. However, significant modifications are necessary to the proposed Appendix K protocol.

API has worked diligently with EPA to integrate OGI monitoring into rules and to develop the specifics of the methodology. These comments are intended to foster a high-quality generic methodology for use at facilities with large process operations.

API believes significant modifications (as offered herein) to the proposed Appendix K are necessary before it could effectively be implemented for use across downstream oil and gas facilities or other process industries. API's recommended changes are intended to proactively address concerns that the proposed requirements:

1) will result in difficulty in finding and retaining, adequate numbers of qualified senior OGI operators;

2) that the monitoring, training and proposed QA/QC requirements are overly burdensome and will not lead to more effective leak detection; and

3) that the ownership of various requirements, and particularly the recordkeeping requirements, are unclear and unnecessarily burdensome.

API's recommended changes also aim to make the Appendix K requirements more straightforward and efficient.

2. Appendix K requirements, even if revised, are not appropriate for most upstream and midstream operations characterized by a great many small, geographically dispersed and often remote facilities, with a limited number of fugitive equipment components.

Appendix K as drafted is unnecessarily burdensome and ineffective for utilization in upstream production facilities, gathering and boosting compressor stations, and transmission compressor stations as discussed in the main body of API's comments on this proposal[2]. OGI protocols for these facilities

[1] Posted at https://www.epa.gov/system/files/documents/2021-11/40-cfr-part-60-appendix-k-proposal_0.pdf

[2] Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review: Proposed Rule 86 *Fed. Reg*. 63110 (November 15, 2021)

should continue to be based on part 60 subpart OOOOa requirements, not Appendix K. The requirements specified in subpart OOOOa that are currently used by operators have consistently proven to be effective and are more appropriate for use in upstream applications.

Appendix K goes beyond the current subpart OOOOa requirements concerning performance specifications, operating envelope, survey time, and records for leaking components and is impractical for upstream operators to implement given the hundreds to thousands of well sites and compressor stations to monitor, the geographic dispersion of these facilities and the lack of on-site resources.

3. Appendix K methodology may be suitable for large, complex process operations in other industries.

A. Proposed Appendix K provides a protocol for performing OGI surveys at complex process operations, such as refineries. It is potentially applicable, with the changes we are recommending, not only for refineries and gas plants, but for many similar, complex processes. On promulgation of Appendix K, permitting authorities are likely to immediately begin requiring its use for a variety of such processes. Furthermore, if the final methodology is resource and cost efficient, many facility owners or operators will apply for approval to use OGI as an alternative to current Method 21 monitoring.

Since the proposed Appendix K clearly identifies in proposed paragraphs 6.1.1 and 6.1.2 where a particular OGI camera is sensitive enough to find leaks and rulemaking or Administrator approval would be needed to allow use of OGI for a process not covered by the current rulemaking, it seems counterproductive to include in Appendix K itself a limitation to only oil and gas source categories. Thereby preventing or delaying, others from realizing the benefits of using OGI. We provide additional specifics and our recommendations in Comment II.2.

B. Assuming reasonable frequency and repair requirements are proposed and our suggested revisions to the proposed Appendix K are implemented, 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."[3] 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)).

[3] 80 *Fed. Reg.* 75191 (December 1, 2015)

4. Resource constraints could make OGI using Appendix K impractical and inefficient.

A. The proposed Appendix K protocol imposes overly burdensome monitoring, training, auditing and other QA/QC requirements that reduces the hours a camera operator can spend monitoring and extends the time it takes to qualify or requalify a camera operator. Training requirements associated with the Appendix K protocol could be reduced in API's view without sacrificing the effectiveness of emission detection efforts.

Additionally, Appendix K requires a senior OGI camera operator to train and oversee other OGI camera operators and in some cases to take videos of monitoring operations, requiring at least a senior operator for every 5-10 OGI camera operators doing actual monitoring. This is a problem for any user of Appendix K. We discuss this in more detail in paragraph B of this comment and throughout these comments.

The establishment of significant and excessive overhead by the proposed Appendix K compared to part 60 subpart OOOOa and other current OGI monitoring requirements reduces the economic advantage for moving to this alternative. OGI technology offers the potential to play a significant role in reducing methane and VOC emissions, reducing leak durations and lowering the cost of monitoring. Imposing additional overhead does not significantly increase leak detection and repair effectiveness, but does increase costs and inefficiencies.

B. A senior OGI camera operator is defined in Section 3.0 of the proposed Appendix K as a "camera operator who has conducted OGI surveys at a minimum of 500 sites over the entirety of their career, including at least 20 sites in the past 12 months, and has completed or developed the classroom, computer or on-line camera operator training as defined in Section 10.2.1."

Paragraph 10.2.2 requires a senior OGI operator to:

- conduct 10 surveys while being observed by a trainee,
- conduct 40 side -by-side surveys with each trainee,
- observe 50 surveys performed by the trainee, and
- perform a follow-up survey as a final test of a new trainee.

Thus, the senior OGI operator is tied up for the duration of trainee classroom training and for 101 surveys per trainee. Additionally, there are proposed quarterly performance audit requirements, which would require at least a day (two 4-hour surveys) of a senior OGI operator's time for each operator being audited. There will be a huge demand for senior OGI operators, and those operators will be doing training and audits rather than monitoring for leaks. While we recommend reasonable reductions in these individual duties that would still assure well-trained OGI camera operators conduct monitoring surveys, we believe the demand for senior OGI camera operators will exceed supply for the foreseeable future and will be an on-going challenge. Conceptually, our desire is to have our most experienced camera operators monitoring for leaks a significant portion of their time, not spending all their time training or auditing. That can only be accomplished if there is an adequate supply of such senior people and if those senior people have enough field monitoring time to keep their skills sharp.

We therefore recommend that, in addition to reducing the time senior operators must spend on training and auditing, the criteria for the senior OGI operator designation be revised. As we specifically address throughout these comments, we believe the functions planned for this operator category can be performed by OGI camera operators with a reasonable amount of current field experience, and such a change in the senior operator criterion will assure enough qualified people will be available to perform the necessary training and auditing functions. Furthermore, the resulting larger pool of senior operators would permit rotating personnel efficiently through monitoring, training and audit functions.

To accommodate this change, we suggest a revised definition of senior "OGI camera operator" in Comment II.6, which removes the requirement as to the career experience of the individual and converts the 20-site current experience requirement to 100 hours.

5. Use of drones as an OGI camera platform

Drones are currently being developed, and in some cases, being used to perform OGI monitoring. They are particularly useful and efficient for monitoring dispersed small sources (e.g., in tankfields) and elevated, hard to reach equipment. **We request that the rulemaking clarify that use of drones is allowed if Appendix K requirements are met and, as discussed in Comment II.1, by removing the limitation in Appendix K that the camera be "hand-held."** While the type of mount needs to be considered in determining if a separate operating envelope is needed for camera configurations used with that mount, this clarification should make it clear that if operating envelope, dwell time and related requirements appropriate for a particular camera model and configuration are met it does not matter how the camera is mounted. **To affect this clarification, we recommend drones be included as an example of a camera platform in the definition of camera configuration and in proposed paragraph 8.3.**

6. While not appropriate for inclusion in Appendix K, fixed continuous monitors should be addressed in referencing rules where appropriate.

In some situations, continuous leak monitoring systems are justified and starting to be used instead of periodic monitoring with portable OGI cameras. As discussed in the main body of these comments, where such systems might be desirable for some situations, the referencing subpart (in this case proposed subparts OOOOb and OOOOc) should address that approach as an alternative to periodic OGI monitoring.

II. Specific Comments and Recommendations on Appendix K

1. General Terminology

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

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

C. In the petroleum operations that Appendix K would apply to under the current proposal[4] and in other operations it may apply to under other rules or permits, a "site" can be anything from a single piece of equipment involving a few potential leak interfaces to a refinery complex involving millions of potential leak interfaces. Thus, monitoring a "site" can take a brief time for one OGI operator (minutes or hours) or require many fulltime OGI operators and take months to complete. Because of this extreme diversity, **API recommends "site" not be the basis for any Appendix K requirements, except where the size of the site is not significant** (e.g., the requirement in Section 9.0 that each "site" have a monitoring plan)**.** Specific suggestions for alternatives to each use of "site" in the draft Appendix K where we believe a change is needed are included below and in the redline version of the proposed Appendix K we have included with these comments.

Additionally, there are requirements assigned to the "site" that could be the responsibility of a contract monitoring organization and could apply at multiple sites. For instance, development of procedures that describe how components will be viewed with the OGI camera (paragraph 9.4) and the requirement to have a plan for avoiding camera operator fatigue (paragraph 9.5). **In these cases, we are recommending that Appendix K provide that the various requirements assigned to the site be either**

[4] Ibid.

reassigned or flexibility be provided to allow a more appropriate assignment of responsibility and to reduce unnecessary or duplicative recordkeeping requirements.

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

E. In setting requirements based on "sites" or "number of surveys" there is a lack of clarity as to whether the requirements require each site to be a different site or each survey to be of a separate set of equipment. This concern would carry over if, as we recommend, the criterion is changed to a monitoring time basis. It would be burdensome and wasteful to interpret these requirements as requiring monitoring of different equipment and, in some cases, it would be infeasible to meet such an interpretation. **We recommend EPA clarify that such requirements do not require monitoring of different equipment for every survey, and we have recommended clarifying language in some of our specific comments and in our redline version of the proposed Appendix K.**

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

2. Paragraph 1.3 Applicability Belongs in a Referencing Subpart, Not in A Test Protocol

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

B. Paragraph 1.3 states "This protocol is not applicable to chemical plants or other facility types outside of the oil and gas upstream and downstream sectors." **We recommend this sentence be deleted.** Appendix K is appropriate for use for some processes in other source categories and there is no reason to preclude that here since Appendix K only becomes applicable when a referencing subpart, permit or the Administrator allows and since adequate camera capability is assured by the requirements in proposed Paragraphs 6.1.1 and 6.1.2.[5] and the other Appendix K requirements.

For instance, there are many Hazardous Organic NESHAP (HON) processes, including within some refineries (e.g., benzene, toluene, xylene (BTX) units), where Appendix K would be immediately useable, with appropriate approvals. There is no reason to preclude the use of OGI and Appendix K, and to forgo any potential emission reductions or efficiencies, for those HON processes where the camera has adequate capability by having this sentence present in Appendix K. Similarly, Appendix K could, with appropriate approvals, be used for Ethylene Production source category units, another type of unit often found within or adjoining a refinery. Deleting this sentence now, would save having to amend Appendix K in the near future, when the first non-oil and gas rule is proposes to allow OGI, or a regulatory authority wishes to require its use for other source categories.

While there will be processes in a chemical or other source category where OGI and Appendix K would not fit, there are many places where it does and the use of OGI in those cases should be encouraged. Assurance that Appendix K is not being misapplied can be further achieved by being specific in the referencing subpart or permit as to process chemistry that must be present to use OGI and Appendix K, or through the permit or Administrator review where it is requested to be used for sources not covered by a referencing subpart. The purpose of part 60 appendices is to provide generic methodologies that do not have to be amended each time they are referenced, and we encourage the Agency to align the Appendix K applicability section with that purpose.

3. Definition of "Fugitive Emission or Leak"

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

[5] 6.1.1 The spectral range of infrared radiation measured by the OGI camera must overlap with a major absorption peak for the chemical target of interest, meaning the OGI camera must be sensitive with a response factor of at least 0.25 when compared to the response factor of propane for the majority of constituents (>75 percent) of the expected gaseous emissions composition

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 butane emissions of 18.5 g/hr. at a viewing distance of 2 metersand a delta-T of 5 °Celsius (C) in an environment of calm wind conditions around 1 meter per second (m/s) or less.

We recommend the following revised definition.

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

4. Definition of "Repair"

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

5. Definition of "Response Factor"

The proposed definition of "response factor" is:

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

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

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

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

If the Agency believes such a limitation is needed, it should focus the limitation on the methodology for developing response factors, propose the methodology they plan to require when the final Appendix K language is proposed, provide for automatic approval after 90 days of any response factor or response factor methodology submitted to the Administrator if no action is taken within that time and grandfather response factors developed prior to the proposal of the Administrator's methodology.

6. Definition of "Senior OGI Camera Operator"

A. Some OGI camera operators are certified thermographers. The thermographic certification requirements for a Level 2 thermograph operator parallel the initial and refresher OGI training requirements that would apply under Appendix K. Thus, **we recommend that certified thermographers be considered as senior OGI camera operators and that they be exempted from the initial training requirements in proposed Paragraphs 10.1 through 10.3.**

To this end, we also recommend adding a definition of a certified thermographer as follows:

> ***Certified Thermographer*** **for the purposes of this Appendix, means a thermographer who has successfully completed the requirements for a Level 2 or higher thermography certificate compliant with ASNT-TC-1A or ISO 18436-7.**

B. Our members report confusion over the 12-month time (i.e., whether it is a calendar 12-months or a rolling 12-months) in the proposed senior OGI camera operator definition. **We recommend, as included in our recommended revised definition below, a sentence be added to the definition of senior OGI camera operator to clarify this point as follows "Previous 12-months means the 365-calender days prior to the day of the activity requiring a senior OGI camera operator."**

C. **Per the discussion in Comment I.4.B, we recommend the proposed definition of senior OGI camera operator be replaced. We suggest the following definition:**

> **A senior OGI camera operator is an OGI camera operator who has performed at least 100 hours of OGI monitoring (excluding their own initial and refresher training time) in the previous 12-months and has either 1) successfully completed the initial and field training specified in Section 10 of this Appendix and has completed any required refresher training or**

2) is a certified thermographer. Previous 12-months means the 365-calender days prior to the day of the activity requiring a senior OGI camera operator.

As discussed in comment II.1.C, “site” is an extremely unclear and imprecise term and we are suggesting that 100 hours of recent monitoring experience (i.e., in the previous 12 months) be specified instead. More critically, we are recommending removal of any “career” experience requirement. We do not believe career experience adds significantly to an operator’s ability to train or audit others. It is recent experience with current equipment and requirements at locations of the type currently being monitored that is critical to quality training and auditing, and we believe a 12-month criterion provides that expertise. Removing the proposed career criterion will increase the availability of senior OGI camera operators as OGI programs are being instituted and the demand for senior operators is at a maximum for training purposes and will make some senior operators available for actual monitoring duty.

One hundred hours of monitoring experience is consistent with the results of the operator experience testing reported in the Appendix K Technical Support Document (TSD)[6]. As shown in Table 4-35 (Overall Blind Survey Results for Leaks Released at 2% Concentration) and Appendix C-3 of the TSD, there was little difference among camera operators above the novice level (<10 hours of monitoring experience). In fact, the two most experienced operators (with >300 hours of field experience and >400 hours of laboratory experience) had the worst and the best results at finding leaks, respectively. The other operators did about equally well and had experience levels at or under 100 hours and some had no field monitoring experience at all. This conclusion is supported by others. In Appendix 1 to the Optical Gas Imaging Feasibility Study Summary Report included in the Appendix K TSD[7], it is reported that a Sage Environmental expert interviewed by EPA’s contractor stated, “that a trusted operator (one who has sufficient imaging experience to generate highly reliable results) has about 1 month or 100 hours of in-the-field use and experience.” Similarly, Texas has concluded that refresher training is not needed for an OGI camera operator with 100 hours in 12-months experience[8], an indication that that level of experience identifies a well-qualified individual.

The work of Zimmerle, et. al.[9] referenced in the TSD evaluated operator experience levels using test facilities typical of upstream equipment. They concluded that “Surveyors from operators/contractors who had surveyed more than 551 sites prior to testing detected 1.7 (1.5–1.8) times more leaks than surveyors who had completed fewer surveys” but they also point out their “data also indicate that all surveyors have a high probability of detecting large leaks” and thus “it is unclear if total emissions (which are generally dominated by large emitters) would be highly impacted.” While there is some variability, the data reported by Zimmerle, et. al. appears to show that their 551-site finding is equivalent to 200-250 hours of monitoring. We believe any operator meeting the >100 hour/12-month criterion we recommend would already have or quickly pass the 200-250 hours of experience and that

[6] Docket Document EPA-HQ-OAR-2021-0317-0079, Eastern Research Group, Technical Support Document: Optical Gas Imaging Protocol, August 2, 2021, Pages 113 and 114

[7] Ibid.

[8] See 30 TAC 115.358(h)(2).

[9] Zimmerle, D., Vaughn, T., Bell, C., Bennett, K., Deshmukh, P., & Thoma, E. (2020). Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions. Environmental Science & Technology, 54(18), 11506-11514. DOI: 10.1021/acs.est.0c01285

emission reduction effectiveness would not be seriously impacted in the interim because large leaks will be readily found by any camera operator.

Our recommended level of experience will assure the senior OGI camera operator duties are well performed and that their knowledge is current while expanding the pool of senior operators to assure an adequate supply and the availability of senior operators to perform monitoring as well as training and quality assurance functions.

It also should be clarified that monitoring hours performed by a senior operator as a quality check of another operator or as part of operator training counts toward the 12-month senior OGI operator monitoring criterion.

D. The proposed definition would seem to require that a senior OGI camera operator must have conducted OGI surveys at 500 different sites in their career and 20 different sites in the past 12 months. We recommend below this criterion be changed to a “hours in the previous 12-months” basis. None-the-less, many OGI camera operators, particularly those associated with a single company or facility, will not have access to many different sites or be able to monitor 100 hours at separate locations. Thus, as recommended in general in Comment II.1.E, **EPA should clarify that any field monitoring counts towards the senior operator’s site or hour’s criterion, whether at the same or separate locations, except for the senior operators own initial and refresher training hours.**

7. Paragraph 5.1 Site Hazards

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

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

8. Section 6 Equipment and Supplies

A. **API supports the spectral range requirements in paragraph 6.1.1.** In refineries and other complex processes likely to eventually become subject to Appendix K, monitored components can contain many hydrocarbons with a range of individual response factors. It is important to making the OGI methodology feasible for these processes to balance the camera’s ability versus the range of components that may be in an emission and our limited ability to precisely characterize stream compositions. We believe the proposed paragraph accomplishes that balance and cameras meeting this specification will be widely applicable and will be able to identify emissions of these materials and thus assure equipment leak emissions are controlled. For upstream operations there is usually a dominant hydrocarbon in the streams being monitored and, therefore, the simpler, less burdensome requirement in §60.5397a(c)(7)(i)(A) is appropriate for those operations.

B. Paragraph 6.1.2 and its subparagraphs specify a minimum camera detection limit for methane and butane and various equipment to be used in demonstrating that those minimum limits are met. Requiring this test for every individual OGI camera is unnecessary since all cameras of a particular model are the same. Some camera configuration changes, as exemplified in the definition of camera configuration can impact detectability (e.g., changes sensitivity setting or camera lens) while other will not (e.g., whether camera is hand-held or mounted on a tripod). Thus, the detection limit demonstration is only needed for each configuration that could impact the detection limit. **We recommend that paragraph 6.1.2 be clarified to indicate that this testing may be performed by the equipment manufacturer for each model camera and for each configuration where a camera configuration parameter could impact the camera detection limit and that this demonstration does not have to be performed for every individual OGI camera.**

C. It is proposed in paragraph 6.1.2 to establish the minimum camera detection limit as detection of 17g/hr. methane and 18.5 g/hr. butane at specific distance, delta T and wind conditions. This is a change from the 60g/hr. (10,000 ppm methane/propane mix) minimum detection limit established in part 60 subpart OOOOa and that is in general use today. EPA explains in the proposal that 17g/hr. is what their current modelling shows is needed from bimonthly OGI to get the same emission reduction for methane as is achieved by subpart OOOOa Method 21 requirements[10] . It was shown previously that the subpart OOOOa OGI requirement is also equivalent to Method 21[11]. Thus, there does not seem to be any reason for changing the minimum detection limit demonstration (and possibly having to replace some cameras), requiring new operating envelope determinations, and potentially requiring changing procedures and permits that already use the OOOOa requirements. **API, therefore, recommends the minimum detection limit requirement from §60.5397a(c)(7)(i)(B)[12] be allowed as an alternative to the proposed paragraph 6.1.2 minimum detection limit and that the operating envelope determination procedure in paragraph 8.5 be revised accordingly.**

[10] Op. Cit., page 63232

[11] Environ. (2004). Development of Emissions Factors and/or Correlation Equations for Gas Leak Detection, and the Development of an EPA Protocol for the Use of a Gas-imaging Device as an Alternative or Supplement to Current Leak Detection and Evaluation Methods. Final Report to the Texas Council on Environmental Technology and the Texas Commission on Environmental Quality.

[12] Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60g/hr. from a quarter inch diameter orifice.

D. To clarify the recordkeeping requirements associated with paragraphs 6.1.1 and 6.1.2 and to eliminate what could be viewed as a requirement for large volumes of unnecessary records, **we recommend that proposed second sentence of paragraph 8.1 be relocated to section 6 as 6.1.3 and that it require paragraph 6.1.2 records to be maintained by the organization doing the demonstration (usually the camera manufacturer)** and not by every site where that camera is being used. **We propose:**

> **6.1.3 Documents demonstrating compliance with paragraphs 6.1.1 and 6.1.2 must be retained with other OGI records by the owner or operator or testing organization, as applicable.**

E. Paragraph 6.2 specifies equipment needed to perform the minimum detection limit testing required by paragraph 6.1.2 and the operating envelopes required in Section 8. For clarity we recommend paragraph 6.2 be modified to be clear on where these requirements apply. **We recommend the following revised paragraph 6.2:**

> **6.2 The following items are needed for the initial performance verification of each OGI camera model configuration, as required by paragraph 6.1.2 and Section 8:**

F. Paragraph 6.2.4 calls for use of a mass flow controller or rotameter capable of controlling the methane and butane rates within a National Institute of Standards and Technology (NIST) traceable accuracy of 5% when testing a camera's detection limit or operating envelope. NIST traceability is not specified for any other instrumentation used in these demonstrations and seems unnecessary for this use. **We recommend the requirement for NIST traceability be removed.**

G. The paragraph 6.2.6 subparagraphs specify requirements for weather stations from which data will be used for the minimum detection limit testing required by paragraph 6.1.2 and the operating envelope testing in Section 8. It specifies the weather information be obtained from a weather station within 1 mile of test location and that the weather station instrumentation meets various listed specifications. In many cases, National Weather Service stations will be the basis for this data, and the testing facility will not have ready access to the instrumentation specifications at that weather station or the ability to influence that equipment. **We therefore recommend that weather data obtained from a National Weather Service Station located within 1 mile of the test location be allowed without requiring the information specified in paragraphs 6.2.6.1 through 6.2.6.5 to be collected.**

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

9. Section 7 Camera Calibration and Maintenance

Our members report their experience with OGI cameras confirms that these cameras do not require any on-going calibration or routine maintenance. Thus, **we support Section 7 as proposed.**

10. Section 8 Initial Performance Verification and Development of the Operating Envelope

A. Paragraph 8.1 requires a record be maintained with other OGI records that each OGI camera meets the minimum detection limit requirements in paragraph 6.1.2. As indicated in Comment II.8.B, we anticipate it will be primarily the camera manufacturer's responsibility to assure the camera meets those specifications. Furthermore, many of these cameras will be used at multiple, separate facilities owned by different entities and it would be difficult and lead to a lack of cohesion for every entity that uses the camera and must maintain OGI monitoring records to have to maintain a copy of that documentation. **API therefore recommends this requirement be revised to require that the manufacturer of the OGI camera or other entity that performs the paragraph 6.1.2 evaluations be required to maintain the records showing compliance with the minimum detection limits and that such a record not be required to be kept by the camera owner or at each location where the camera is used. Further, we recommend this recordkeeping requirement be moved to paragraph 6.1, where it better fits (See Comment II.8.D).**

B. Operating Envelopes

a. As we discuss in Comment II.8.C, EPA's data shows equivalent performance is obtained by using the same methane/propane mix as used in part 60 subpart OOOOa for establishing camera minimum detection limits and operating windows as is obtained using methane and butane as proposed. Therefore, it is unnecessarily burdensome to require sources to change from a methane/propane mixture to methane and butane. **We therefore request that Appendix K allow use of either approach for setting operating envelope parameters (i.e., use methane/propane mix or use methane and butane)**.

b. As with the requirements in paragraph 6.1.2, in most cases establishing operating envelopes per the requirements of proposed paragraphs 8.2 through 8.6 can most efficiently, and with minimum methane and butane emissions, be developed by the manufacturer for each camera model configuration that could impact the camera's capabilities. Some camera configuration variations will not impact the camera capabilities and thus will not need a separate operating envelope. For instance, it usually makes no difference if a camera is hand-held, mounted on a tripod or mounted on a drone. If the mount is appropriately located to meet the maximum monitoring distance parameter of its operating window and is stationary (e.g., drone is hovering if a drone mount is in use) the same operating envelope is applicable. While there may be cases where a different operating envelope is needed for a unique monitoring situation, that will be the exception rather than the rule. In most cases, a single or a few operating envelopes will suffice for most monitoring. The key, which is addressed in Section 9 of the proposal, is assuring all equipment components being monitored are within an established operating envelope when they are monitored. **We, therefore, recommend that it be made clear in paragraph 8.3 that operating envelopes may be developed by the manufacturer or by others for each camera model and that separate operating envelopes are only required for camera configurations that impact the camera's ability to reliably locate leaks.**

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

d. Finally, it would be a clarification if the wording of paragraphs 8.3 through 8.6 be revised to indicate there may be multiple operating envelopes for a particular camera configuration. **We suggest a few specific wording revisions in the Appendix K redline included in this submission**.

11. Section 9 Conducting the Monitoring Survey

A. General

a. Throughout Section 9 of the proposal the monitoring plan requirements are stated as requirements for each site. However, much of the information is not site specific (e.g., procedure for assuring operating envelope conditions are met, procedures for documenting monitoring surveys). Most of those procedures are generic for a particular camera and monitoring approach and apply to many sites, often sites with different owners. Many of the procedures in a monitoring plan will be the responsibility of the camera owner or contract monitoring firm. There is no justification for forcing every site to develop those procedures or even to have a record of the generic ones. Rather than trying to list who should be responsible for each procedure **we recommend these requirements (except for paragraph 9.7) be reworded to simply identify monitoring plan content requirements without specifying who is responsible for them.** We make specific recommendations as to maintenance of the monitoring plan records in the next comment and in our recordkeeping comments in Section 17 of these comments.

b. Section 9 of the proposal requires that each site have a monitoring plan that describes the procedures for conducting a monitoring survey. Proposed paragraph 12.2 requires the facility must maintain a record of the site monitoring plan. We comment on the specifics of recordkeeping paragraph 12.2 in Comment II.17.B, however, we believe that both the section 9 and paragraph 12.2 need to be clarified that it is not required that a copy of the plan be maintained at every site. Typically, such a plan would be developed centrally and would be available electronically as needed by the camera operators when they are monitoring that site. **We suggest the introductory sentence to section 9.0 be revised to the following.** We recommend an equivalent change in our recommended changes to paragraph 12.2.

> **9.0 A monitoring plan that describes the procedures for conducting a monitoring survey at each site must be readily available to the camera operator.**

B. **API generally supports the proposed daily initial verification checks in paragraph 9.1.** In our experience these checks assure the OGI camera is functioning properly. However, we see no value in the burden imposed by paragraph 9.1.4 that requires a video record of the camera imaging a butane lighter or other validation source. It is more than adequate to simply have confirmed that the camera sees the butane lighter image as part of confirming the entire 9.1 set of requirements were met. It is overly burdensome and unnecessary to require daily video records of that determination. Storing thousands of videos, no matter how short, is difficult and there needs to be a significant justification for any such a requirement. **API recommends paragraph 9.1.4 be deleted.**

C. Paragraph 9.3 requires a monitoring plan for each site to identify monitoring survey methodologies that ensure all regulated components are monitored. It provides only three approaches that may be used. All three approaches are extremely complex, and the burdens imposed are often not justified versus other alternatives. We comment on some of the specifics of the three approaches next (in Comment II.11.D.b), though we believe paragraph 9.3 should be replaced in its entirety.

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

Limiting survey monitoring methodologies to only three is also inconsistent with the stated intent of the current proposal[13]. On page 63165 of the current proposal, EPA states:

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

[13] Ibid.

For these reasons, **we request language based on Part 60 Subpart OOOOa §60.5397a(d)(1)[14] be substituted for the proposed paragraph 9.3. That language we recommend is as follows:**

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

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

a. The proposed three approaches are clearly intended for use at larger operations where many monitoring locations are needed and there is a large infrastructure and significant resources to allow marking monitoring locations, mapping routes and maintaining this information. Many locations subject to the current rulemaking are smaller facilities or portions of a facility (e.g., a flow meter station or a tankfield pump station) where monitoring will require one pair of observations (two views of the components) or at the most a few observations. It is unnecessary and overly burdensome to have to manage repetitive route maps, to place and maintain monitoring location markers or even identify GPS coordinates in such situations. Thus, if section 9.3 is not replaced, **we recommend an additional option be added that would apply to facilities where less than 25 monitoring observations are needed to monitor all components regulated by a referencing subpart or permit.** The term "monitoring observation" refers to each pair of camera locations[15] used to visualize a particular collection of equipment leak components (e.g., a piping manifold, a meter station). Under that option, the monitoring plan would allow for a description of the approach that will be used (e.g., monitor all components from two views at least 90 degrees apart) and a list of the facilities or facility locations to which this option applies.

b. For the reasons discussed in Comment II.1.C, **we recommend the word "site" in paragraph 9.3 (if maintained) be removed. We suggest the paragraph start with "Conduct monitoring using …"**

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

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

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[14] §60.5397a(d)(1) states, "(1) If you are using optical gas imaging, your plan must include procedures to ensure that all fugitive emissions components are monitored during each survey. Example procedures include, but are not limited to, a sitemap with an observation path, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components."

[15] Typically, at least two different views of potential leak sources are used for OGI monitoring.

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

E. Paragraph 9.4 and Table 14-1 specify minimum dwell times for observations.

a. **API requests EPA explain the basis for the dwell time requirements in the formal proposal of Appendix K (i.e., the Table 14-1 entries)**, so we can provide scientifically valid comments.

b. API believes that setting prescriptive dwell times is unnecessary and introduces inefficiencies and wasteful burdens. An experienced camera operator will determine dwell time based on the circumstances – some views may require an extended dwell time and other views may need shorter dwell time. **Dwell time should be an element of operator training and auditing, but not specified in Appendix K.** Dwell time is already included in paragraph 10.2.1.5 training requirements, in monitoring plan requirements and dwell time issues would become readily apparent in the final field training test and during performance audits and other quality control activities as required by paragraph 11.1. In the work of Zimmerle[16], et. al. dwell times were not identified on a per component basis. However, they did report the range of times operators took to complete surveys of three different typical upstream installations, where leaks were artificially introduced. They reported the range of monitoring times as follows.

Test Site	Monitoring Time (min)
1	3-52 (mean 19)
2	1-89 (mean 18)
3	9-108 (mean 39)

With that wide range of monitoring times, it is impossible to identify minimum dwell times that do not introduce inefficiency. Unnecessarily long dwell times result in inefficient emission reductions and take time and resources away from other compliance activities with greater environmental benefits. Zimmerle's work clearly identifies that experienced operators adjust the dwell time of an individual observation to account for environmental considerations (e.g., background) and for the type of equipment and process conditions and the likelihood of leaks. It is the ability to make these adjustments that makes the monitoring process efficient. If dwell times are not flexible, efficiency is lost, since extended time is spent looking at the many components that are not leaking or even likely to leak. Zimmerle also reported that while the number of smaller leaks identified increased with increased monitoring times, identification of larger leaks was not significantly impacted, so the mass of emissions identified was not overly sensitive to the monitoring time.

[16] Ibid.

Specifying a dwell time discourages a camera operator from adjusting for prevailing conditions. Once the specified dwell time is reached there is no reason for an operator to spend additional time, even if the situation requires it.

F. Paragraph 9.5 requires that the monitoring plan address camera operator fatigue. It includes specific requirements to address this concern. Imposing specific ergonomic requirements such as proposed in this paragraph is outside the scope of an EPA method. Furthermore, the approach must be tailored to the situation. For instance, under this rulemaking most monitoring will be in short bursts with travel time between monitoring locations. Nothing specific is needed in these situations to prevent operator fatigue. In more densely populated situations relief may be needed, but the times for breaks need to be matched to the situation. For instance, arbitrarily requiring a break 5 minutes before lunch or quitting time makes no sense. Similarly, stopping a monitoring round that takes 23 minutes to complete for a break at twenty minutes (as specified in the proposal) is equally nonsensical. Additionally, 20 minutes may be too long between breaks in some situations. For instance, if the camera operator had to climb a hundred-foot tower to perform monitoring or monitor in particularly hot situations.

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

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

We suggest paragraphs 9.6.1 and 9.6.2 be replaced with the following to address this variability

> **9.6.1 For each monitoring day or change in facility, record the date, approximate start and stop times and the name of facility where the monitoring is performed.**
>
> **9.6.2 At the start of each monitoring day or a change in facility, record the weather conditions, including ambient temperature, wind speed, relative humidity,and sky conditions.**

H. Leaks

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

b. Paragraph 9.7.1 requires that if a leak is identified, a video clip be taken, and the leak tagged for repair. The final sentence of the paragraph suggests the video clip is needed to allow the operator to find the leak. Since it is required that the leak be tagged, it does not seem there would be a need for a video or even a still picture to help find the leak. As indicated in the subpart OOOOa quote below, that subpart only requires tagging or an image, not both. No justification for requiring both is provided in the record.

Furthermore, there are situations where immediate repair or tagging of a leak can impose a potential safety problem and thus the absolute requirement to tag all leaks is infeasible. Safety issues occur, for instance, if the leak is in an extremely hot piece of equipment (e.g., in a furnace process outlet line), where there is no immediate safe access available (e.g., in a pipe rack, on the side of a tower), or where toxics such as hydrogen sulfide is or may be present. In these cases, a video or a digital picture could be helpful in identifying the leak location and the burdens associated with requiring such a record are justified. As we have previously discussed, any video record requirement adds burden and can be difficult to reliably meet. A digital picture, as opposed to a video, has the advantage of being much easier to store and can better show reference points that help identify the leak location when compared to video. Paragraph 60.5397a(h)(4)(ii) of part 60 subpart OOOOa requires a digital picture of leaks that are not immediately repaired or tagged, and that approach has been in successful use since September of 2015. Paragraph 60.5397a(h)(4)(ii) states:

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

Thus, **we request that paragraph 9.7.1 be revised to parallel the part 60 subpart OOOOa approach, allowing either a video or a digital picture and only imposing that requirement where a leak is not immediately repaired or tagged and that only a written record of the leak information be required otherwise.**

I. Paragraph 9.7.3 requires a 5-minute per day quality assurance video for each camera operator. The paragraph specifies that the video must document the procedures the operator uses to survey (e.g., dwell times, angles, distances, backgrounds) and the camera configuration. It is unclear how such a video clip would show compliance with that list of items. For instance, dwell times, angles, distances, backgrounds will vary for every monitoring occurrence, since they depend on the equipment being monitored, the location of the camera relative to the component locations, the background and the weather. A video does not show whether those parameters are being met. A video does not show whether all operating envelope criteria are being met, even for the situation being viewed. Furthermore, video of camera operators who know they are being videoed is unlikely to be representative. The required quarterly (or as we recommend annual) performance audits, proper training, the daily equipment startup checks and the quality assurance requirements in paragraph 11.1 provide all the appropriate quality assurance much more effectively and efficiently than this proposed video requirement. Furthermore, creating extensive video records that are difficult to reliably store, provide no useful information, and are unlikely to ever be reviewed, imposes a large and overly burdensome mandate.

We are also concerned that EPA underestimates the burden of storing video files, specifically storing the 5-minute per camera operator per day videos required in paragraph 9.7.3. There are actual examples of data storage issues associated with the requirement in MACT CC (63.670(h)(2)), which requires recordkeeping of photos taken of a flare every 15 seconds (or 2,102,400 images per year per flare). For at least one of our member companies operating several refineries, the flare images are *not* stored on the Cloud. Rather, they are saved locally on a server for several reasons, primarily for security. Refineries often have very tight Information Technology (IT) security systems because of the nature of the industry. Additionally, some member companies have experienced a loss of some of the photos because of power outages or other technical issues associated with handling the sheer volume of images. The flare images add up quickly, and the videos required by paragraph 9.7.3 will as well. For comparison, a high-definition video is 60 frames per second. Assuming 5 such videos per day for 250 days per year for a refinery then represents 22,000,000 images. The burden of saving these videos on the slight chance someone may want to review one is not justified, since, as discussed above, we do not see them providing any compliance assurance value.

Paragraph 9.7.3 and the corresponding entry in the table in paragraph 11.3 should be deleted.

12. Paragraph 10.2 Initial OGI Camera Operator Training

Paragraph 10.2.1 addresses initial “classroom” training of OGI camera operator trainees. As discussed in Comment II.1.F, it needs to be clarified throughout Appendix K that this can be computer-based training and does not have to be in-person classroom training.

Paragraph 10.2.2 addresses the required field training. It calls for a minimum of 1) 10 site surveys where the trainee is observing a senior OGI operator, 2) 40 site surveys where monitoring is performed side-by-side with a senior OGI operator, 3) 50 site surveys where a senior OGI operator observes the trainee performing monitoring and 4) a final survey where a senior OGI operator performs a follow-up survey that demonstrates the trainee did not miss any persistent leaks. There are many issues with these requirements as follows.

A. Paragraph 10.1 calls for a training plan. It includes a sentence saying, “If the facility does not perform its own OGI monitoring, the facility must ensure that the training plan for the company performing the OGI surveys adheres to this requirement.” **API recommends this sentence be deleted.** Any company contracting for OGI monitoring services has a responsibility to assure that those services meet any applicable requirements. There is no reason a training plan is any more critical than any of the other requirements of Appendix K. Nor is it clear how individual facilities would "ensure" compliance with the training plan requirements or why each facility would have that responsibility if the monitoring contract involved many facilities. Imposing an unclear burden on every facility that does OGI monitoring using Appendix K aggregates to a large and unnecessary burden.

B. As discussed in Comment II.1.C, site is an imprecise term and could require monitoring for minutes at a location with only a few potential leak components or could require monitoring for months at a location with hundreds of thousands of potential leak components. Thus, **we recommend the word "site" be deleted from these paragraphs and these training requirements should be based on monitoring hours as discussed below.**

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

In our experience, 34 hours of field monitoring training is unnecessary to assure well-trained operators. In fact, Texas has concluded only 24 hours of total initial training is necessary[17]. Based on that experience, the need to train large numbers of OGI camera operators initially and the likely shortage of senior OGI camera operators, **we recommend 1) field monitoring training be limited as discussed below, 2) field monitoring training require monitoring surveys of approximately 20-minutes each and 3) that it be clarified that the observational portions of the training do not have to be one-on-one**. We amplify on these recommendations in the following comments (II.12.D and E). In combination with the initial classroom or computer-based training, these recommendations would provide more than the 24-hour minimum required by Texas.

D. Paragraph 10.2.2 requires 10 surveys where the trainee observes a senior operator, 40 surveys side-by-side with a senior OGI operator and 50 surveys with a senior operator overseeing the trainee. In our experience, this is excessive, particularly the amount of side-by-side surveying. Nor as discussed below and elsewhere, will there be enough senior OGI operators to perform these functions if the requirements for reaching senior operator status are unchanged. We believe side-by-side monitoring can be done with operators meeting our suggested revised senior OGI camera operator definition with no loss in quality versus senior operators meeting the proposed definition. It is also important that the

[17] §115.358(h)(1) of Title 30 of the Texas Administrative Code requires "Operator training. Any person that performs the alternative work practice in this section shall comply with the following minimum training requirements.

(1) The operator of the optical gas imaging instrument shall receive a minimum of 24 hours of initial training on the specific make and model of optical gas imaging instrument before using the instrument for the purposes of the alternative work practice.

revised language be clear that the observational training does not have to be one-to-one (see our suggestions in the Appendix K redline attached to these comments). Thus, **we recommend these requirements be revised to 10 20-minute monitoring surveys where a group of trainees observes a senior OGI camera operator, 50 20-minute monitoring surveys where a senior operator oversees a group of trainees and 5 20-minute monitoring surveys side-by-side with a qualified operator.** The proposed final survey test in proposed paragraph 10.2.2.4 (modified as discussed below) would complete the training. This would provide a total of approximately 23 hours of field experience for each trainee prior to their starting to perform monitoring surveys.

E. Final Field Training Test

a. Paragraph 10.2.2.4 requires a final monitoring test where the trainee conducts an OGI survey, and a senior OGI camera operator follows behind with a second camera to confirm the trainee's survey results. Consistent with our recommendation for performance audits below, **we recommend this final test be of 1-hour duration (e.g., 3 20-minute periods) to assure a sizable number of components are monitored.**

b. The criterion for passing this final test is "The trainee must achieve zero missed persistent leaks relative to the senior OGI camera operator …" We believe the criterion of zero missed persistent leaks is unreasonable and should be revised. First, even if the follow-up survey is performed immediately after the trainee's survey, there can be changes in leak rates, interferences, etc. that occur and can cause a marginal leak to be observed in one survey and not the other. Second, a leak may occur continually through a dwell period and still not occur at another time. Thus, it is quite possible in the real world that a leak can be observed in one survey and not occur in another survey even if the other survey is just a few minutes earlier or later. These differences can occur for either survey. In the real world, it is just as likely the trainee will observe "persistent" leaks that the qualified operator does not. EPA has acknowledged this potential issue for marginal leaks even in carefully controlled situations by establishing a 75% criterion (3 out of 4) when establishing operating envelopes for an OGI camera.[18] As proposed, paragraph 10.2.2.4 also presumes the senior operator monitoring always observes more leaks than the trainee observes. That is unreasonable and the passing criteria must allow for either situation. For these reasons, **we recommend that the criterion for passing the final test be changed to at least 90% agreement or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified.**

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

[18] See paragraph 8.5.3 of the proposal.

13. Paragraph 10.3 Refresher training

A. Paragraph 10.3 requires annual refresher training for OGI operators. In our experience annual refresher training is unnecessary considering the ongoing quality assurance requirements, and the typical amount of oversight that occurs. Even in the TSD, it is recognized that refresher training is not always needed. For instance, it is stated on page 115 that "If OGI technicians are regularly sent out to the field to perform surveys, then re-validating their performance may not be necessary, but could also be as simple as having a superior repeat a survey and report on the established technician's performance." **We recommend the refresher training be on a three-year interval.**

B. There are many OGI monitoring programs already underway and thus there are some experienced camera operators already in place. It would be unnecessarily burdensome for them to have to go through the entire initial training program when they first must meet Appendix K requirements. They would only need to understand the specific requirements of this Appendix. Thus, **we recommend that an OGI camera operator with at least 24 hours of OGI monitoring experience in the previous 12 months, but no previous Appendix K experience, only be required to go through the refresher level of training rather than the full initial training and then pass the field training final test in paragraph 10.2.2.4.**

14. Paragraph 10.4 Performance Audits

A. Paragraph 10.4 requires quarterly performance audits. Our experience suggests that formal quarterly audits of camera operators are excessive. We note that other similar work practice programs, such as the Method 21 LDAR monitoring program has been successfully in service for more than 40 years without a similar audit requirement. Considering the requirements for an on-going quality control program in proposed paragraph 11.1, annual performance audits are certainly adequate. **We recommend changing this requirement to annual audits**.

Besides reducing burdens and freeing camera operators for actual monitoring activities, this change in audit frequency has the added benefit of reducing the demand on senior OGI camera operator time, thereby allowing more time for senior operators to do monitoring and training.

B. Since senior OGI camera operators will carry out any required performance audits, they will automatically frequently review monitoring requirements and have an opportunity to identify and correct any issues of their own. Such issues would be apparent as they compare results if a comparative monitoring option is used and when reviewing, either in person or via video the auditee. Thus, **API recommends senior OGI camera operators not be required to undergo performance audits.**

C. Paragraph 10.4.1 outlines a performance audit option using comparative monitoring and paragraph 10.4.2 outlines a performance audit option using video review. We comment on the specifics of those approaches in our next comment (Comment II.14.D). We support providing alternative audit approaches, since there will be many variants in monitoring organizations, monitoring schedules, senior OGI camera operator availability, and facilities, but believe there are more than two alternatives to evaluating the performance of a camera operator. Therefore, **we recommend that the performance audit methodologies that will be used be required to be included in the monitoring plan as already implied in proposed paragraph 11.1 and that the approaches in paragraphs 10.4.1 and 10.4.2 only be cited as examples.**

Alternative approaches include visual observation by a senior OGI camera operator (as opposed to their reviewing a video) or observation by a monitoring supervisor or review of results from monitoring at a test facility, among others.

D. Performance Audit Procedures

a. Paragraphs 10.4.1.1 and 10.4.2.1 require audits of at least 4-hours with no persistent leaks identified by the auditor that were missed by the auditee. Four hours is an excessively lengthy period and is not needed to assess if an auditee is monitoring correctly. One-hour is more than adequate to determine if the auditee is following procedures and can identify leaks. Nor is a 4-hour requirement it a reasonable use of resources, tying up an OGI camera operator and an auditor for more than a day per audit (4-hours for the trainee monitoring and 4 hours for the follow-up senior OGI operator survey) and for video audits a third person (taking the video) for half a day. **We recommend the 4-hour requirement be changed to require audits of 1-hour total duration (i.e., 3 20-minute periods) and, as discussed in Comment II.14.A, these audits only be required annually.**

b. Paragraph 10.4.2 provides a performance audit procedure wherein a senior OGI camera operator observes the auditee by reviewing a video of that auditee performing monitoring. While that approach is useful where senior operators are not readily available, in many cases it would be easier for the senior operator to simply observe the auditee by following them around. This also eliminates the issues associated with needing an additional (i.e., third) person to take the video and of storing the video. **Thus, if this requirement is maintained, we recommend it also allow for a senior operator to simply observe the auditee and not have to record a video.**

c. For all the reasons presented in Comment II.12.E.b, **we also recommend that the criterion for passing the audit be changed to at least 90% agreement of the number of persistent leaks found or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified.**

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

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

f. Paragraphs 10.4.1.2 and 10.4.2.2 specify retraining requirements for an operator that fails the audit criterion. The retraining requires a minimum of 1) 10 site surveys where the trainee is observing a senior OGI operator, 2) 5 site surveys where monitoring is performed side-by-side with a senior OGI operator, 3) 10 site surveys where a senior OGI observes the monitoring and 4) a final survey where a senior OGI operator performs a follow-up survey that demonstrates the operator in training did not miss any persistent leaks. First, as discussed in Comment II.1.C **we recommend the word "site" be deleted**

from these paragraphs and the monitoring requirements be expressed on a time basis. Second, we believe the retraining proposed is excessive and overly burdensome. Failures to observe a leak or to follow some aspects of the monitoring procedure are situation specific. General retraining dilutes the focus on the real problem(s) and uses up precious monitoring time and senior resources on issues that are not a problem. Therefore, we believe it is impossible to specify a retraining paradigm that is generic and resource efficient. Rather, **we believe the requirement should be to specify that retraining is required to address monitoring aspects observed to be an issue during the audit and that the auditee must then pass a new comparative audit by achieving at least 90% agreement on the number of persistent leaks or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified.**

15. Paragraph 10.5 Returning Operators

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

16. Section 11 Quality Assurance and Quality Control

A. Consistent with our recommendation in Comment II.11.J to delete Paragraph 9.7.3, **the second sentence of paragraph 11.2 should be deleted.**

B. We have commented individually on the QA/QC requirements proposed throughout. **Paragraph 11.3 summarizes those requirements and will need to be updated to match the final version of the Appendix.** We have included recommended revisions in the redline version of Appendix K that we are submitting with these comments.

Additionally, some of the wording in the frequency column of that table is unclear as to who is responsible and how often and on what basis the QA/QC activity is required. We have suggested improved wording and addition of specific references to the paragraph containing the requirement in the redline version of Appendix K that we are submitting with these comments.

17. Section 12 Recordkeeping

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

B. Paragraph 12.2 says, "The facility must maintain the following records in a manner that is easily accessible to all OGI camera operators:" However, except for paragraph 12.2.1 (the site monitoring plan) and 12.2.4 (operating envelope limits) the other listed records are associated with the camera, and many cameras will be used at multiple facilities and may not be owned by the facility or even the facility owner. In fact, it can be anticipated that many cameras will be owned by a monitoring company. Even in the case of the site monitoring plan, as we discussed in Comment II.11.A, much of the content of that plan will be the responsibility of the camera owner. While a facility owner or operator will have significant input relative to monitoring routes and safety issues, the camera owner or monitoring contractor is the appropriate owner of this plan it would be their responsibility to see that their camera operators have ready access to the plan, not the responsibility of the facility owner unless the monitoring personnel are in-house. **Thus, "facility" should be deleted from the paragraph 12.2 wording, and it should be rephrased to say, "The following records must be maintained, as applicable" and a sentence added to require that operating envelope limits and applicable site monitoring plans be readily accessible to camera operator.**

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

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

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

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

Attachment B

Suggested Redlines to Prepublication Draft Appendix K

Determination of Volatile Organic Compound and Greenhouse Gas Leaks Using Optical Gas Imaging
[API recommended changes shown in redline mode]

1.0 Scope and Application

1.1 Analytes.

Analytes	CAS No.
Volatile Organic Compounds (VOCs)	No CAS number assigned.
Methane	74-82-8
Ethane	74-84-0

1.1.1 This protocol is applicable to the detection of VOCs, including hazardous air pollutants (HAPs),and hydrocarbons, such as methane and ethane.

1.2 Scope. This protocol covers surveys of process equipment using Optical Gas Imaging (OGI) cameras in oil and gas upstream and downstream sectors (from production to refining to distribution). Thespecific component focus for the surveys is determined by the applicable subpart, and can include, but is not limited to, valves, flanges, connectors, pumps, compressors, open-ended lines, pressure relief devices,and seal systems.

1.3 Applicability. This protocol is applicable to equipment leak components at facilities ~~all facility types from the upstream and downstream oil and gas sectors and may apply to well heads, compressor stations, boosting stations, petroleum refineries, gas processing plants, and gasoline distribution facilities~~ when referenced by an applicable subpart. ~~This protocol is not applicable to chemical plants or other facility types outside of the oil and gasupstream and downstream sectors.~~ 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.

2.0 Summary

2.1 A ~~hand-held,~~ field portable infrared (IR) camera capable of imaging the target gas species is employed to survey process equipment and locate fugitive or leaking gas emissions. By restricting the amount of incoming thermal radiation to a small bandwidth corresponding to a region of interaction for the gas species of interest, the camera provides an image of an invisible gas to the camera operator. The camera type and manufacturer are not stated in this protocol, but the camera used must meet the specifications and performance criteria presented in Section 6. The keys to becoming proficient and maintaining leak detection proficiency using OGI cameras are proper camera operator training with sufficient field experience and conducting OGI surveys frequently throughout the year.

3.0 Definitions

Ambient air temperature means the air temperature in the general location where the OGI survey isbeing performed.

Applicable subpart means a subpart in 40 CFR part 60, 61, 63, or 65 that requires the monitoring of regulated equipment for fugitive emissions or leaks, for which this protocol is referenced.

Camera Configuration means different ways of setting up an OGI camera that affect the detection capability. Examples of camera configurations that can be changed include the operating mode (*e.g.,* standard versus high sensitivity or enhanced), the lens, the portability (*e.g.*, handheld versus tripod or drone mounted), and the viewer (*e.g.*, OGI camera screen versus an external device like a tablet).

Certified Thermographer, for the purposes of this Appendix, means a thermographer who has successfully completed the requirements for a Level 2 or higher thermography certificate compliant with ASNT-TC-1A or ISO 18436-7.

Delta temperature (delta-T or ΔT) means the difference in temperature between the emitted process gas temperature and the surrounding background temperature. It is an acceptable practice in the field to assume that the emitted process gas temperature is equal to the ambient air temperature.

Dwell time means the time required to survey a manageable subsection of a scene in order to provide adequate probability of leak detection. The dwell time is the active time the operator is looking for potential leaks and does not begin until the scene is in focus and steady.

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

Imaging is the process of producing a visual representation of emissions that may otherwise be invisible to the naked eye.

Operating envelope means the range of conditions (*i.e.*, wind speed, delta-T, viewing distance) within which a survey must be conducted to achieve the quality objective.

Optical gas imaging camera means any ~~hand-held,~~ field portable instrumentation that makes visible emissions that may otherwise be invisible to the naked eye.

Persistent leak is any leak that is not intermittent in nature.

~~*Repair* means that a component is adjusted, or otherwise altered, to eliminate a leak.~~

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

Senior OGI camera operator is a camera operator who has performed at least 100 hours of OGI monitoring (excluding their own initial and refresher training time) in the previous 12-months and has either 1) successfully completed the initial and field training specified in Section 10 of this Appendix and has completed any required refresher training or 2) is a certified thermographer. ~~has conducted OGI surveys at a minimum of500 sites over the entirety of their career, including at least 20 sites in the past 12 months, and has completed or developed the classroom camera operator training as defined in Section 10.2.1.~~ Previous 12-months means the 365-calender days prior to the day of the activity that requires a senior OGI camera operator.

4.0 Interferences

4.1 Interferences from atmospheric conditions can impact the operator's ability to detect gas leaks. Itis recommended that conditions involving steam, fog, mist, rain, solar glint, high particulate matter concentrations, and extremely hot backgrounds are avoided for a survey of acceptable quality.

5.0 Safety

5.1 Site Hazards. Prior to applying this protocol in the field, the potential hazards at the survey site should be considered; advance coordination with the site is critical to understand the conditions and applicable safety policies. This protocol does not address all of the safety concerns associated with its use. ~~It is the responsibility~~

~~of the user of this protocol to establish appropriate health and safety practices and determine the applicability of regulatory limitations prior to implementing this protocol.~~

5.2 Hazardous Pollutants. Several of the compounds encountered over the course of this protocol maybe irritating or corrosive to tissues (*e.g.*, heptane) or may be toxic (*e.g.*, benzene, methyl alcohol, hydrogen sulfide). Nearly all are fire hazards. Chemical compounds in gaseous emissions should be determined from process knowledge of the source. Appropriate precautions can be found in reference documents, such as reference 13.1.

6.0 Equipment and Supplies

6.1 An OGI camera meeting the following specifications is required:

6.1.1 The spectral range of infrared radiation measured by the OGI camera must overlap with a major absorption peak for the chemical target of interest, meaning the OGI camera must be sensitive with a response factor of at least 0.25 when compared to the response factor of propane for the majority of constituents (>75 percent) of the expected gaseous emissions composition.

6.1.2 Your OGI camera must be capable of imaging a gas that is half methane, half propane at a concentration of 10,000 ppm at a flow rate of ≤60 grams per hour (g/hr.) from a quarter inch diameter orifice. Alternatively, t~~T~~he OGI camera must be capable of detecting (or producing a detectable image of) methane emissions of 17 ~~grams per hour (~~g/hr.~~)~~ and butane emissions of 18.5 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.

6.1.3 Documents demonstrating compliance with paragraphs 6.1.1 and 6.1.2 must be retained with other OGI records by the owner or operator or testing organization, as applicable.

6.2 The following items are needed for the initial performance verification of ~~the~~ each OGI camera model configuration, as required by paragraph 6.1.2 and Section 8:

6.2.1 Methane test gas, chemically pure grade (99.5%) or higher and Butane test gas, chemically pure grade (99%) or higher, or~~.~~

6.2.2 ~~Butane test gas, chemically pure grade (99%) or higher.~~A gas that is half methane, half propane at a concentration of 10,000 ppm.

6.2.3 Release orifice, ¼ inch in diameter.

6.2.4 Mass flow controller or rotameter, capable of controlling the gas emission rate within ~~NIST traceable~~ an accuracy of 5 percent.

6.2.5 An industrial fan, capable of adjusting the sustained nominal wind speeds at regular intervals up to 15 m/s, with the ability to maintain a set speed within 20 percent of the target wind speed.

6.2.6 A National Weather Service Station located within 1 mile of the test location. Alternatively, a meteorological station within 1 mile of the location of the testing capable of providing representative data and meeting the following minimum specifications at least once every hour:

6.2.6.1 Ambient temperature readings accurate to at least 0.5 °C, with a resolution of 0.1 °C or less, and a minimum range of -20 to 70 °C.

6.2.6.2 Ambient pressure readings accurate to at least 1.5 millibar (mbar), with a resolution of 0.1 mbar or less, and a minimum range of 700 to 1100 mbar.

6.2.6.3 Wind speed readings accurate to at least 0.1 m/s, with a resolution of 0.1 m/s or less, and a minimum range of 0.1 to 20 m/s.

6.2.6.4 Wind direction readings accurate to at least 5 ~~°C~~degrees, with a resolution of 1 ~~°C~~degree or less.

6.2.6.5 Relative humidity readings accurate to at least 2 percent, with a resolution of 0.1 percent or less, and a minimum range of 10 to 90 percent noncondensing.

6.2.7 A temperature-controlled background large enough for viewing the emissions plume and capable of maintaining a uniform temperature. Uniform is defined as all points on the background deviating no more than 1 °C from the average temperature of the background.

6.2.8 T-type probe thermocouple and readout, accurate to at 1 °C, for measuring the test gas at the point of release.

6.2.9 T-type surface skin thermocouple and readout, accurate to at 1 °C, for measuring the background immediately behind the test gas.

6.2.10 Device to measure the distance between the OGI camera and the release point (e.g., tape measure, laser measurement tool), accurate to at least 2 centimeters (cm), with a resolution of at least 1 cm.

7.0 Camera Calibration and Maintenance

The camera does not require routine calibration for purposes of gas leak detection but may require calibration if it is used for thermography (such as with ΔT determination features).

8.0 Initial Performance Verification and Development of the Operating Envelope

8.1 Determine that the OGI camera meets the specification in Section 6.1. ~~A document demonstrating compliance with this requirement must be retained with other OGI records.~~

8.2 Field conditions such as the viewing distance to the component to be monitored, wind speed, ambient air temperature, and the background temperature all have the potential to impact the ability of the OGI camera operator to detect the leak. It is important that the OGI camera has been tested under the full range of expected field conditions in which the OGI camera will be used.

8.3 ~~An o~~Operating envelopes must be established for field use of the OGI camera. ~~The~~ An operating envelope must be confirmed for all potential configurations that impact the camera's capabilities, such as high sensitivity modes, available lenses, and, in some cases, handheld versus tripod or drone mounted. ~~Conversely, separate operating envelopes may be developed for different configurations.~~ If, in addition to or in lieu of the display on the camera itself, an external device (*e.g.*, laptop, tablet) is intended to be used to visualize the leak in the field, the operating envelope must be developed while using the external device. If the external device will not be used at all times, use of the external device is considered a separate configuration, and ~~the~~ operating envelope testing must be performed for both configurations. Imaging must not be performed when the conditions are outside of the developed operating envelope. Operating envelopes may be developed by a camera manufacturer for a particular OGI camera model and configuration or by others,

8.4 Development of ~~the~~ an operating envelope is to be performed using the test gas composition in either Section 6.2.1 or 6.2.2, flowrate, and orifice diameter described in Section 6.1.2, and must include the following variables:

8.4.1 Delta-T, regulated through the use of a temperature-controlled background encompassing approximately 50 percent of the field of view, with no potential for solar interference;

8.4.2 Viewing distance from the OGI camera to the component being imaged; and

8.4.3 Wind speed, controlled through the use of an industrial fan.

8.5 Determine the operating envelope using the following procedure:

8.5.1 Set up the methane/propane test gas at a flow rate of ~~17~~ 60 g/hr. or setup the methane test gas at a flow rate of 17 g/hr. The same test gas(s) used for demonstrating that the minimum detection limit required in section 6.1.2 must be used when determining operating envelopes.

8.5.2 For this flow rate, the ability of the OGI camera to produce an observable image is challenged by ranges of the variables in Sections 8.4.1 through 8.4.3.

8.5.3 A panel of no less than 4 observers who have been trained using the OGI camera and who have a demonstrated capability of detecting gaseous leaks will observe the test gas release for each combination of delta-T, distance, and wind speed. A test emission is determined to be observed when at least 75 percent of the observers (i.e., 3 of the 4 observers) see the image.

8.5.4 If the pure methane test gas was used, r~~R~~epeat the procedures in Sections 8.5.2 and 8.5.3 using the butane test gas at a flow rate of 18.5 g/hr.

8.5.5 When testing with the pure methane and pure butane test gases, t~~T~~he operating envelope to be used in the field for each OGI camera configuration tested is the more restrictive operating envelope developed between those~~the~~ two test gases.

8.5.6 Repeat the procedures in Sections 8.5.1-8.5.5 for each camera configuration that will be used to conduct surveys in the field.

8.6 The results of the testing to establish ~~the~~ an operating envelope, including supporting videos, must be documented and kept with other OGI records of the organization performing the test. Camera owners must maintain a record of the allowed operating envelope parameters for each camera they own and that record must be readily available to the camera operator.

9.0 Conducting the Monitoring Survey

~~Each site must have a~~ A monitoring plan that describes the procedures for conducting a monitoring survey at each site must be readily available to the camera operator. At a minimum, the monitoring plan must include the following:

9.1 A description of ~~Prior to imaging, the operator must perform~~ a daily verification check to be performed prior to imaging to confirm that the camera is operating properly. This verification must consist of the following at a minimum:

9.1.1 Confirm that the OGI camera software loads successfully and does not display any error messages upon startup;

9.1.2 Confirm that the OGI camera focuses properly at the shortest and longest distances that will be imaged;

9.1.3 Confirm that the OGI camera produces a live IR image using a known emissions source, such as a butane lighter or a propane cylinder;

~~9.1.4 Confirm that the OGI camera can record data and/or leak footage properly by using the~~

~~check in Section 9.1.3 as a test run and saving the resulting file with the survey record; and~~

9.1.~~5~~4 Confirm that the OGI camera can perform the delta-T check function as expected, if this function will be used meet the requirement in Section 9.2.3.

9.2 The ~~site must develop~~monitoring plan must include a procedure for ensuring that the monitoring survey is performed only when conditions in the field are within the operating envelope established in Section 8. This procedure must include the following:

9.2.1 Determination of the camera operator's maximum viewing distance from the surveyed components, based upon wind speed and expected delta-T at the monitoring site. This determination must be made each day a survey is conducted.

9.2.2. Description of how the viewing distance from the surveyed components, the wind speed, and the delta-T will be monitored to ensure that the monitoring survey is conducted within the limits of the operating envelope;

9.2.3 Description of how the operator will ensure an adequate delta-T is present in order 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);

9.2.4 Description of how the operator will recognize the presence of and deal with potential interferences and/or adverse monitoring conditions, such as steam, fog, mist, rain, solar glint, extremely high concentrations of particulate matter, and hot temperature backgrounds;

9.2.5 Description of how the operator will deal with changes in site conditions during the survey, especially as it relates to the camera operator's maximum viewing distance.

~~9.3 The site must conduct monitoring surveys using a methodology that ensures that all the regulated components within the unit or area are monitored. This must be achieved using one of the following three approaches. The approach chosen and how the approach will be implemented must be described in the monitoring plan. The use of a component database can help make the survey process more efficient, but, the component database is not a substitute for the approaches described below.~~

~~9.3.1 Use of a route map or a map with designated observation locations. The map must be included as part of the monitoring plan, with a predetermined sequence of process unit monitoring (such as directional arrows along the monitoring path) depicted or designated observation locations clearly marked.~~

~~9.3.2 Use of visual cues. The facility must develop visual cues (*e.g.*, tags, streamers, or color-coded pipes) to ensure that all regulated components were monitored. The monitoring plan must describe whatvisual cue method is used and how it will be used to ensure all components are monitored during the survey.~~

~~9.3.3 Use of global positioning system (GPS) route tracing. The facility must document the path taken during the survey by capturing GPS coordinates along the survey path, along with date and time stamps. GPS coordinates must be recorded frequently enough to document that all regulated components were monitored. The monitoring plan must describe how often GPS coordinates will be recorded and how the route tracing will ensure all regulated components are monitored.~~

9.3 Your monitoring plan must include procedures to ensure that all equipment leak components as defined in the referencing subpart or permit are monitored. Example procedures include, but are not limited to, a map or electronic database with an observation path or GPS coordinates, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components.

9.4 The ~~site must develop~~monitoring plan must include a procedure that describes how components will be viewed with the OGI camera. In general, a component should be imaged from at least two different angles, and the operator must dwell on each angle ~~for a minimum of 5 seconds~~ before changing the angle, distance, or focus and dwelling again. For a complex scene of components, the operator must divide the scene into manageable subsections and dwell on each angle ~~for a minimum of 5 seconds per component in the field of view (e.g., for a subsection with 5 components, the minimum dwell time would be 25 seconds)~~. ~~The operator may reduce the dwell time for complex scenes based on the monitoring area and number of components in the subsection as prescribed in Table 14-1, provided the manageable subsection for the angle fills greater than half of the field of view of the camera.~~ The procedure must discuss changes, if necessary, to the imaging mode of the OGI camera that are appropriate to ensure that leaks from all ~~regulated equipment leak~~ components regulated by the referencing subpart or permit can be imaged.

9.5 The monitoring plan must include~~site ownermust have~~ a plan for avoiding camera operator fatigue, as physical, mental, and eye fatigue are concerns with continuous field operation of OGI cameras. ~~The OGI camera operator should not survey continuously for a period of more than 20 minutes without taking a rest break. Taking a rest break between surveys of process units may satisfy this requirement; however, for process units or complex scenes requiring continuous survey periods of more than 20 minutes, the operator must take a break of at least 5 minutes after every 20 minutes of surveying.~~

~~Note: If continuous surveying is desired for extended time periods, two camera operators can alternate between surveying and taking breaks.~~

9.6 The monitoring plan must include~~site owner must have~~ a procedure for documenting monitoring surveys, including:~~.~~

9.6.1 For each monitoring ~~survey~~day or change in facility, record the date and approximate start and end times.

9.6.2 At the start of ~~the survey~~each monitoring day or a change in facility~~, when transitioning to the next major process area, and at the end of the survey~~, record the weather conditions, including ambient temperature, wind speed, relative humidity, and sky conditions.

9.7 The site must have a procedure for documenting fugitive emissions or leaks found during the monitoring survey.

9.7.1 If a leak is found and the leak is not immediately repaired, the leaking component must be tagged for repair or an image obtained to show the location of the leak. If the component is not immediately repaired or tagged, ~~at a minimum~~ capture a digital image or at a minimum a 10-second video clip of the leaking component and keep the video clip or digital image with the rest of the OGI survey documentation. ~~The leaking component must be tagged for repair, and~~ T~~t~~he date, time, and location of ~~the~~ all leaks must be recorded and stored with the OGI survey records. ~~This information can be used to visually assist the operator with locating components that need repair.~~

9.7.2 If no emissions are found, no recorded footage is required to demonstrate that the component was not leaking.

~~9.7.3 At least once each monitoring day, each operator must record a quality assurance (QA) verification video that is a minimum of 5 minutes long. The video must document the procedures the~~

~~operator uses to survey (*e.g.*, dwell times, angles, distances, backgrounds) and the camera configuration.~~

9.8 The ~~site's~~ monitoring plan must describe the process that will be used to ensure the validity of the monitoring data as detailed in Section 11.

10.1 The facility or company performing the OGI surveys must have a training plan which ensures and monitors the proficiency of the camera operators. Training should include ~~classroom~~ instruction and field training on the OGI camera and external devices, monitoring techniques, best practices, process knowledge, and other regulatory requirements related to leak detection that are relevant to the facility's OGI monitoring efforts. ~~If the facility does not perform its own OGI monitoring, the facility must ensure that the training plan for the company performing the OGI surveys adheres to this requirement.~~ Certified thermographers are exempt from the requirements of paragraphs 10.2 through 10.4.

10.2 Prior to conducting monitoring surveys, camera operators must complete initial training and demonstrate proficiency with the OGI camera and any external devices to be utilized for detecting a potential leak.

10.2.1 At a minimum, the training plan must include the following ~~classroom~~ training elements as part of the initial training:

10.2.1.1 Key fundamental concepts of the OGI camera technology, such as the types of images thecamera is capable of visualizing and the technology basis (theory) behind this capability.

10.2.1.2 Parameters that can affect image detection (*e.g.*, wind speed, temperature, distance,background, and potential interferences).

10.2.1.3 Description of the components to be surveyed and example imagery of the various types ofleaks that can be expected.

10.2.1.4 Calibration, operating, and maintenance instructions for the OGI camera used at the facility.

10.2.1.5 Procedures for performing the monitoring survey according to the ~~site~~ applicable monitoring plan, including the daily verification check; how to ensure the monitoring survey is performed only when the conditions in the field are within ~~the~~ an established operating envelope; the number of angles a component or set of components should be imaged from; how long to dwell on the scene before changing the angle, distance, and/or focus; how to improve the background visualization; the procedure for ensuring that all ~~regulated~~ equipment leak components regulated by the referencing subpart or permit are visualized; required rest breaks; and documenting surveys.

10.2.1.6 Recordkeeping requirements.

10.2.1.7 Common mistakes and best practices.

10.2.1.8 Discussion on the regulatory requirements related to leak detection that are relevant to thefacility's OGI monitoring efforts.

10.2.2 At a minimum, the training plan must include the following field training elements as part of the initial training:

10.2.2.1 A minimum of 10 ~~site~~ 20-minute monitoring surveys with OGI where ~~the~~ trainees ~~is~~

~~observing~~ 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 ~~40~~ 5 20-minute monitoring~~site~~ surveys 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 ~~provides~~ providing instruction/correction where necessary.

10.2.2.3 A minimum of 50 20-minute monitoring ~~site~~ surveys with OGI where the trainee performs ~~the~~ monitoring surveys independently with ~~the~~ a senior OGI camera operator trainer present and the senior OGI camera operator ~~provides~~ providing oversight and instruction/correction to the trainee(s) where necessary.

10.2.2.4 A final ~~site~~ 1-hour monitoring survey test where the trainee conducts the OGI survey and a senior OGI camera operator follows behind with a second camera to confirm the OGI survey results. Ninety percent agreement on the number of persistent leaks found or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified ~~The trainee~~ must be achieved ~~zero missed persistent leaks relative to~~for the ~~senior~~ OGI camera ~~operator~~ trainee to be considered authorized for independent survey execution. If the required agreement is not achieved, the senior OGI operator must counsel the trainee and then another 1-hour test performed. If there is a lack of adequate agreement on the second test the trainee must complete the refresher training requirements in paragraph 10.3, before taking the final test again.

10.3 Refresher training.

10.3.1 All OGI camera operators must attend a~~n annual~~ ~~classroom~~ training refresher every three years. This refresher can be shorter in duration than the initial classroom, computer or on-line training but must cover all the salient points necessary to operate the camera (e.g., performing surveys according to the monitoring plan, best practices, discussion of lessons learned throughout the year). OGI camera operators who have not performed any OGI monitoring in the last 12-months, must take refresher training before restarting monitoring.

~~10.2.3~~10.3.2 OGI camera operators with at least 24 hours of OGI monitoring experience in the previous 12-months, but no experience operating under Appendix K, must take refresher training per paragraph 10.3.1 and pass a final test per paragraph 10.2.2.4.

10.4 Performance audits for all OGI camera operators, except senior OGI camera operators, must occur on ~~a quarterly~~an annual basis with at least ~~one~~ three months between two consecutive audits. Performance audits must be conducted according to procedures outlined in the monitoring plan. ~~one of the following procedures~~Performance audit procedures may include, but are not limited to paragraphs 10.4.1 or 10.4.2 of this section:

10.4.1 Performance audit by comparative monitoring. Comparative monitoring in near real-time is where a senior OGI camera operator reviews the performance of the employee being audited by performing an independent monitoring survey.

10.4.1.1 Following the survey conducted by the camera operator being audited, the senior OGI camera operator will conduct a survey of the same equipment of at least ~~4~~1-hour~~s~~ ~~to ensure that no persistent leaks were missed~~.

10.4.1.2 If there is less than 90% agreement in the number of~~a~~ persistent leaks identified or a difference of more than 1 persistent leak if less than 10 persistent leaks are identified~~ is missed by the camera operator being audited~~, then the camera operator being audited will need to retrain on the monitoring aspects believed deficient. ~~following the field portion of the initial training outlined in Section 10.2.2. For the retraining, the required number of site surveys with OGI is reduced to 5 full side-by-side comparative surveys in Section 10.2.2.2 and 10 supervised surveys in Section 10.2.2.3before t~~The audited camera operator must ~~achieve zero missed persistent leaks on the final survey test to be recertified~~then repeat the paragraph 10.4.1.2 comparative monitoring test.

10.4.2 Performance audit by ~~video~~ observational review. The camera operator being audited must submit unedited and uncut video footage of their OGI survey technique to a senior OGI camera operator for review or a senior OGI camera operator must visually observe the camera operator.

10.4.2.1 The ~~videos~~ observation period must ~~contain~~be at least ~~4~~ 1 hour~~s~~ of~~ survey footage~~. ~~If a single survey is less than 4 hours, footage from multiple surveys may be submitted; however, all videos necessary to cover a 4-hour period must be recorded and submitted for review.~~ The senior OGI camera operator will review the survey technique of the camera operator being audited, as well as look for any missed leaks.

10.4.2.2 If there is less than 90% agreement in the number of~~the senior OGI camera operator finds any~~ persistent leaks ~~missed by the camera operator being audited~~identified or a difference of no more than 1 persistent leak if less than 10 persistent leaks are identified or the auditor finds that the survey techniques during the ~~video~~ review do not match the monitoring plan required by Section 9, then the camera operator being audited will need to retrain on the monitoring aspects believed deficient.~~the field portion of the initial training outlined in Section 10.2.2~~. ~~For retraining, the required number of site surveys with OGI is reduced to 5 full side-by-side comparative surveys in Section 10.2.2.2 and 10 supervised surveys in Section 10.2.2.3 before the audited camera operator must achieve zero missed persistent leaks on the finalsurvey test to be recertified.~~ The audited camera operator must then repeat the paragraph 10.4.2 observational test.

~~10.4.3 If a camera operator is not scheduled to perform an OGI survey during a quarter, then the audit must occur with the next scheduled monitoring survey.~~

~~10.5 If an OGI camera operator has not conducted a monitoring survey in over 12 months, then they must repeat the initial training requirements in Section 10.2.~~

11.0 Quality Assurance and Quality Control

11.1 As part of the facility's monitoring plan, the facility must have a process which ensures the validity of the monitoring data. Examples may include routine review and sign-off of the monitoring data by the camera operator's supervisor, periodic comparative monitoring using a different camera operator as part of a continuing training verification plan described in Section 10, or other due-diligence procedures. The monitoring plan must also include specifics of the annual performance audit procedures that will be used to comply with paragraph 10.4.

~~11.2 Daily OGI camera verification must be performed and a brief (5-10 second) video recorded as described in Section 9.1. Additionally, the daily QA verification video for each operator must be recordedas described in Section 9.7.3.~~

~~11.3~~11.2 The following table is a summary of the mandatory QA and quality control (QC) measures in this protocol with the associated frequency and acceptance criteria. All of the QA/QC data must be documented and kept with other OGI records.

Summary Table of QA/QC

Parameter	**QA/QC Specification**	**Acceptance Criteria**	**Frequency**
OGI Camera Design	Spectral bandpass range	Must overlap with major absorption peak of the compound(s) of interest as specified in paragraph 6.1.1.	Once prior to conducting the initial survey~~s~~ of an area and any time the compounds of interest is expected to change due to process changes.
OGI Camera Design	Initial camera performance verification	Must be capable of detecting (or producing a detectable image of) a 10,000 ppmv methane/propane mixture at 60 g/hr. or of methane emissions of 17 g/hr and butane emission of 18.5 g/hr at a viewing distance of 2 meters and a delta-T of 5 °C in an environment of calm wind conditions around 1 m/sor less. (Paragraph 6.1.2)	Once for each camera model or configuration prior to conducting initial surveys.
Developing the Operating Envelope	Observation confirmation	Leak is observed by 3 out of 4 panel observers for specific combinations of delta-T, distance, and wind speed. (Paragraph 8.5)	Once prior to conducting surveys and prior to using a new camera model or configuration.
OGI Camera Functionality	Verification Check	Meet the requirements of Section 9.1 to confirm that the OGI camera software loads successfully and that the camera focuses properly, produces a live IR image, records, and, as applicable, performs the delta-T check function.	Each monitoring day, for each camera prior to conducting a survey with that camera.
Camera Operator Training	Classroom, computer or on-line training	Meet the requirements of Sections 10.2.1 and 10.3 with the issuing of a certificate or record of attendance kept in the employee or OGI records file.	Prior to a camera operator conducting surveys, with a~~n~~ triannual refresher, and after prolonged periods (greater than 12 months) of not performing OGI surveys.
Camera Operator Training	Field training	Meet the requirements of Section 10.2.2 while maintaining the records of facilities ~~visited~~ monitored by the trainee in the employee or OGI records file along with a certificate or record of completion ~~issued upon the achievement of zero missed persistent leaks~~ of the final survey test specified in paragraph 10.2.2.4 with the date of the survey recorded.	Prior to a camera operator conducting surveys and after prolonged periods (greater than 12 months) of not performing OGI surveys.

~~OGI Camera Operator Performance~~	~~QA verification video~~	~~Record a video that is a minimum of 5 minutes long that documents the procedures the operator uses to survey *(e.g.*, dwell times, angles, distances, backgrounds) and the camera configuration.~~	~~Each monitoring day.~~
OGI Camera Operator Performance	~~Quarterly~~ Annual performance audits	Comparative monitoring: ~~No missed~~Ninety percent agreement on the number of persistent leaks over a ~~4~~1-hour survey as determined by a senior OGI camera operator's survey. OR Video review: Ninety percent agreement on the number of ~~No missed~~ leaks as determined by a senior OGI camera operator and OGI survey technique in submitted videos matches the requirements in Section 9. OR Other audit procedure specified in the applicable monitoring plan.	Every ~~3~~ 12 months, with at least ~~1~~ 3 month between consecutive audits.

12.0 Recordkeeping

12.1 Records required by this Appendix must be kept~~The facility must keep the records required by this protocol~~ for a period of 5 years, unless otherwise specified in an applicable subpart.

12.2 The following records must be maintained, as applicable.~~The facility must maintain the following records in a manner that is easily accessible to all OGIcamera operators:~~ Applicable site monitoring plans and operating envelope limitations must be readily accessible to the camera operators.

12.2.1 Complete site monitoring plan with all the required elements;

12.2.2 Initial OGI camera performance verifications;

12.2.3 Camera maintenance and calibration records over the lifetime of the OGI camera; and

12.2.4 The OGI camera operating envelope limitations.

12.3 All data supporting development of the operating envelope must be maintained by the organization that develops an operating envelope.

12.4 The training plan, and for each OGI camera operator, the following records must be maintained by the employer of the OGI camera operator or the owner or operator of a location being surveyed, as applicable. These may be kept in a separate location for privacy but must be easily accessible to program administrators and available for review if requested by the Administrator: For certified thermographers, these records are not required but a record of the thermographer's certification and date of its expiration is required.

12.4.1 The date of completion of initial OGI camera operator classroom, computer or on-line training;

12.4.2 The date of the passed final ~~site~~ survey test following the initial OGI camera operator field training;

12.4.3 The number and date of all training surveys performed, and if the survey is part of initial field training or retraining, notation of whether the survey was performed by observing a senior OGI camera operator, side-by-side with a senior OGI camera operator, or with oversight from a senior OGI camera operator;

12.4.4 Performance audit methodologies.

~~12.4.4~~12.4.5 The date and results of ~~quarterly~~ annual performance audits; and

~~12.4.5~~12.4.6 The date of any~~the annual classroom~~ training refresher.

12.5 Monitoring survey results shall be kept ~~in a manner that is accessible to those technicians executing repairs~~ and at a minimum must contain the following:

12.5.1 Daily verification check;

~~12.5.2 Camera operator's maximum viewing distance for the day, based upon wind speed and expected delta-T at the monitoring site.~~

~~12.5.3~~12.5.2 Identification of the ~~site~~facilities surveyed and the survey date and start and end times;

~~12.5.4~~12.5.3 Name of the OGI camera operator performing the survey and identification of the OGI camera used to conduct the survey. The identification of the OGI camera can be the serial number or an assignedname/number labeled on the camera, but it must allow an operator or inspector to tie the camera back to the records associated with the camera (*e.g.*, maintenance, initial performance verification);

~~12.5.5~~12.5.4 Weather conditions, including the ambient temperature, wind speed, relative humidity, and skyconditions, at the start of the ~~survey~~monitoring day~~,~~ and when ~~transitioning to the next major process area~~changing the facility being surveyed~~, and at the end of the survey~~;

12.5.5 Video footage or digital photo of any leak detected and not immediately repaired or tagged along with the date, time, and component location of all leaks detected. This video or digital record shall be maintained in a manner that is accessible to those technicians executing repairs; and

12.5.6 Records identified in the monitoring plan to demonstrate that all equipment leak components are monitored per paragraph 9.3.~~The daily QA verification video for each operator; and~~

12.5.7 ~~GPS coordinates for the route taken, if Section 9.3.3 is used to ensure all regulated components are monitored.~~

13.0 References

13.1 U.S. Department of Health and Human Services. (2010). NIOSH Pocket Guide to Chemical Hazards. NIOSH Publication No. 2010-168c. Also available from https://www.cdc.gov/niosh/docs/2010-168c/default.html.

13.2 U.S. Environmental Protection Agency. (2021). Technical Support Document: Optical Gas Imaging Protocol (40 CFR Part 60, Appendix K).

13.3 U.S. Environmental Protection Agency. (2020). Optical Gas Imaging Stakeholder Input Workshop Presentations and Discussion; Summary Letter Report.

13.4 Zeng, Y., J. Morris, A. Sanders, S. Mutyala, and C. Zeng. (2017). Methods to Determine Response

Factors for Infrared Imagers used as Quantitative Measurement Devices. *Journal of the Air &Waste Management Association*, *67*(11), 1180-1191. DOI: 10.1080/10962247.2016.1244130. Availableonline at: https://doi.org/10.1080/10962247.2016.1244130.

13.5 Zimmerle, D., T. Vaughn, C. Bell, K. Bennett, P. Deshmukh, and E. Thoma. (2020). Detection Limits of Optical Gas Imaging for Natural Gas Leak Detection in Realistic Controlled Conditions. *Environmental Science & Technology*, *54*(18), 11506-11514. DOI: 10.1021/acs.est.0c01285.

~~*14.0 Tables, Diagrams, and Flow Charts*~~

~~Table 14-1. Dwell Time (in seconds) by Subsection Area and Scene Complexity~~

~~**Monitoring Area (m²)**~~	~~**Components in Subsection**~~ ~~**2-3**~~	~~**4-5**~~	~~**5-10**~~	~~**10-20**~~	~~**>20**~~
~~**0.125**~~	~~5~~	~~10~~	~~15~~	~~20~~	~~25~~
~~**0.25**~~	~~5~~	~~15~~	~~20~~	~~25~~	~~30~~
~~**0.50**~~	~~10~~	~~15~~	~~25~~	~~30~~	~~*~~
~~**1.0**~~	~~10~~	~~20~~	~~30~~	~~*~~	~~*~~
~~**>1.0**~~	~~*~~	~~*~~	~~*~~	~~*~~	~~*~~

~~* The camera operator must either reduce the subsection volume, the scene complexity, or both by moving closer to the components or changing the viewing angle.~~

~~The operator must divide the scene into manageable subsections and image each subsection from at least two different angles. The dwell time for each angle must be a minimum of 5 seconds per component in the field of view. The operator may reduce the dwell time based on the monitoring area and number of components as described in this table, provided the manageable subsection for the angle fills greater than half of the field of view of the camera. The depth of components within the monitoring area must be less than 0.5 meters.~~

Attachment C

Cost Effectiveness Evaluation for Retrofit of Existing Pneumatic Controllers

Introduction

The purpose of this analysis was to identify the minimum number of controllers that would be cost-effective to retrofit at existing well sites, central tank batteries, and compressor stations based on API member cost information. We utilized EPA's model plant analysis, which was provided by EPA in a Microsoft Excel Workbook *'Pneumatic Controllers Costs and Emissions.xlsx'.* Our review of the model plant analysis determined some assumptions made by EPA should be re-evaluated. Our analysis includes the following updates:

- *Assumptions on the types of reliable technologies available to retrofit pneumatic controllers to non-emitting,*
- *Assumptions of the capital and annual operating costs for these technologies,*
- *Assumptions regarding the ratio of pneumatic controller types at an average facility (what EPA refers to as a model plant), and*
- *Assumptions on the emission factor applied for intermittent controllers that would be part of a monitoring and repair program (which EPA also proposed under fugitive emission monitoring).*

Costs

EPA assumed companies would use grid power or solar systems to power electric controllers. For grid power scenarios, EPA costs were limited to the costs of controllers ($4,000 each) and a control panel for grid connection ($4,000). For solar power scenarios, EPA costs were limited to the cost of electric controllers ($4,000 each), a control panel ($4,000), a single 140 W solar panel ($500), and 100 Amh batteries ($400 each). EPA also included installation and engineering costs based on 20% of equipment costs, with total estimated installation costs varying between $4,420 and $8,040. EPA did not include any annual operating or maintenance costs within their assumptions.

API members have converted natural gas driven pneumatic controllers to compressed instrument air systems powered by the grid (when accessible) or natural gas/diesel generators.[1] Costs associated with a typical instrument air system include a regenerative dryer, inlet filter, tank to store compressed air, insulated enclosure for the compressor and dryer, junction box, controllers for the compressor system, and voltage boosters. Additional costs for solar based systems would include higher cost gel or AGM batteries, sufficient number of batteries, and higher numbers of solar panels required in areas of less sunlight such as for Wyoming and North Dakota. Additional costs associated with use of natural gas or diesel generators to power instrument air systems might also include monthly rental fees.[2] An instrument air system typically also requires annual maintenance at a cost of between $2,000 and $4,000 per year depending on the size of the system.

Through a blinded survey conducted a third party, API members provided cost data for converting pneumatic controllers to non-emitting. For smaller facilities, the average cost for a grid powered

[1] API members are only in initial phases of testing the reliability of solar based instrument air systems and costs are not available for a smaller installation.

[2] Monthly rental fees for a third-party generator can run between $8,000 upwards of $25,000 based on the size of the facility. We did not include these additional fees in this analysis.

instrument air system was estimated at $51,000 and for a natural gas generator powered instrument air system around $60,000. These costs include equipment and installation costs. There are also annual maintenance costs associated with both types of systems as mentioned above. For our analysis, we assume an average annual maintenance cost of $3,000.

Count of Controllers

EPA assumed that for existing site retrofits the small, medium and large model plants each contained a high bleed pneumatic controller. This is an incorrect assumption, which is supported by data reported to EPA pursuant to 40 CFR Part 98, subpart W. Data extracted from Envirofacts for the 2020 calendar year clearly shows the breakdown of high bleeds is only 1% for the production segment and 3% for the gathering and boosting segment as summarized in Table C-1. For our analysis, we utilized the assumption that there are 30% continuous low bleed controllers and 70% intermittent controllers at an existing facility.

Table C-1. Counts of Pneumatic Controllers Reported for the 2020 Calendar Year pursuant to 40 CFR Part 98, Subpart W

2020 Reporting Year GHGRP Data	Onshore petroleum and natural gas gathering and boosting [98.230(a)(9)]		Onshore petroleum and natural gas production [98.230(a)(2)]	
Device Type	**Count**	**% of total**	**Count**	**% of total**
High-Bleed Pneumatic Devices	4,067	3%	11,292	1%
Intermittent Bleed Pneumatic Devices	93,202	69%	592,456	72%
Low-Bleed Pneumatic Devices	38,153	28%	221,612	27%
Total	135,422	100%	825,360	100%

Emission Factors

As documented in API's Compendium of GHG Emission Methodologies for the Natural Gas and Oil Industry[3] in Table 6-15:

- The average emission factor should only be used for controllers that are not routinely monitored as part of a proactive monitoring and repair program or the monitoring status is unknown.
- The normal operation emission factor should be applied to controllers that are found to be operating normally as part of a proactive monitoring and repair program.

When intermittent controllers are properly functioning, gas is typically emitted only when the controller actuates. Since EPA has proposed to include intermittent controllers within the fugitive emission monitoring requirements, the intermittent controller would be monitored routinely and repaired or replaced if malfunctioning. Therefore, the more appropriate emission factor that should be utilized for

[3] https://www.api.org/~/media/Files/Policy/ESG/GHG/2021-API-GHG-Compendium-110921.pdf

the pneumatic controller analysis is the properly functioning intermittent controller emission factor of 0.28 scf whole gas/controller-hr and not the average emission factor of 9.2 scf whole gas/controller-hr that EPA applied in their analysis.

Results

Our review indicates that it is not cost effective (as prescribed by EPA) to retrofit gas driven controllers to non-emitting unless there are at least 15 to 30 controllers at an existing site, depending on the single or multi-pollutant approach that EPA typically uses for evaluation. Our results, which follow the analysis format outlined by EPA, are provided in Table C-2.

Table C-2. Cost-Effectiveness Determination for the Minimum Number of Controllers that Should be Considered for Retrofit

Model Plant	Control Option[a]	Count of Controllers[b]	Emissions Reduction- Per Facility (tpy)[c]		Capital Cost[d]	Without Savings					With Savings				
						Annual Cost ($/yr)[d]	Cost Effectiveness ($/ton)		Multipollutant Cost Effectiveness ($/ton)		Annual Cost ($/yr)[d]	Cost Effectiveness ($/ton)		Multipollutant Cost Effectiveness ($/ton)	
			VOC	Methane			VOC	Methane	VOC	Methane		VOC	Methane	VOC	Methane
Minimum # of controllers Multi-Pollutant	Grid power Instrument air system	15	0.66	2.36	$51,000	$8,600	**$13,980**	**$3,886**	$6,990	$1,943	$8,198	**$13,327**	**$3,705**	**$6,664**	**$1,852**
	Natural gas generator instrument air system		0.66	2.36	$60,000	$9,588	**$15,586**	**$4,332**	$7,793	$2,166	$9,186	**$14,933**	**$4,151**	**$7,467**	**$2,076**
Minimum # of controllers Single Pollutant	Grid power instrument air system	30	1.31	4.72	$51,000	$8,600	**$6,990**	**$1,943**	$3,495	$971	$7,797	**$6,337**	**$1,762**	**$3,169**	**$881**
	Natural gas generator instrument air system		1.31	4.72	$60,000	$9,588	**$7,793**	**$2,166**	$3,896	$1,083	$8,785	**$7,140**	**$1,985**	**$3,570**	**$992**

a. Grid Power Instrument Air Systems are assumed to be for locations with available onsite grid power access (assuming a step-down transformer is in place).

b. Counts of Controllers include 30% low bleed and 70% intermittent bleed, which is consistent with trends reported to EPA under 40 CFR Part 98, subpart W for the 2020 calendar year.

c. Emission baseline updated to denote use of properly functioning intermittent controller based on Table 6-15 of the Compendium of GHG Emission Methodologies for the Natural Gas and Oil Industry. This change will appear in the Emission Reduction - Per Facility Columns for methane and VOC.

d. Costs updated to reflect API member company data presented in Table 3 of API comment document (refer to Comment 2.8) based on technologies currently being deployed. This includes an additional $3,000 of annual maintenance costs to ensure instrument air system is functioning properly. Cost info updates are denoted by red font.

Attachment D

API Comments on EPA's Updates under Consideration for the 2022 Inventory of Greenhouse Gas (GHG) Emissions and Sinks

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November 16, 2021

Ms. Melissa Weitz
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Re: API Comments on EPA's Updates under Consideration for the 2022 Inventory of Greenhouse Gas (GHG) Emissions and Sinks

Dear Ms. Weitz,

The American Petroleum Institute (API) appreciates the opportunity to review and provide comments on the proposed updates the U.S. EPA is considering for estimating greenhouse gas (GHG) emissions for the 2022 GHG Inventory (GHGI). The current set of comments addresses the methodologies outlined in EPA's September 2021 technical memoranda on: (a) abandoned oil and gas wells; (b) post-meter emissions; (c) use of Gas Star and Methane Challenge reductions; (d) midstream activity data; and (e) emissions from anomalous well events.

API represents all segments of America's natural gas and oil industry. 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. Our 600 members produce, process, and distribute most of the nation's energy. Most of our members will be directly impacted by the way emissions from their operations are depicted in the national GHGI.

API's aim is to make sure that the GHGI emission estimates used are based on the best and most current data available, reflect actual industry practices and activities, and are technically correct. To assist EPA in the endeavor API has participated in EPA's stakeholders' process and expert review phases of the GHGI development process, providing comments and recommendations on the agency's proposed methodologies. API appreciates the continued engagement with EPA through the multi-stakeholders process.

API's comments below are designed to provide feedback on the information the Agency is seeking from industry along with additional input to inform the proposed updated methodologies. For some of the updates under considerations API is providing supplemental information while for others API recommends that EPA reconsider the merit of adopting the proposed revised methodologies, at this time, without allowing additional time for obtaining information about relevant practices.

Updating Abandoned Wells methodology[1]

- API commented previously on Abandoned Wells emissions when EPA introduced the update for the 2018 GHGI. API noted that the studies conducted so far have limited geographical coverage and may not be nationally representative. To clarify, EPA uses the "entire US" emission factors from the Townsend-Small study, which include the much higher Eastern US (Appalachian - Ohio) emission factors. They then use these same Eastern US factors from Townsend-Small coupled with emissions from Kang 2016 to develop EF's for Appalachian basin abandoned wells. API recommends that EPA should use the lower "western US" emission factors for abandoned wells outside of the Appalachian basin.

- Additionally, the Townsend-Small Appalachia data are dominated by one well with emissions of 146 grams/hr that is about an order of magnitude higher than any other well, plugged or unplugged, in the Townsend-Small data. API contends that it is not appropriate to include this well in the emission factor for the entire US. Also, to date no emissions data are available from the state of Texas or many other major producing areas, calling into question the representativeness of the extrapolation of the results of the current studies to a nationwide estimate of the contribution of CH_4 emissions from Abandoned Wells to the GHGI.

- API requests from EPA a better explanation of how it estimated the number of 1.1 million historical abandoned wells, which are not captured in the Enverus database. Moreover, API maintains that EPA should not assume that all historical (pre-Enverus) wells are unplugged, without further supporting information. Looking at the restructured Enverus data at the end of 1975, which is the date EPA used to develop its estimate of historical (pre-Enverus) wells, indicates that 72% of the wells that would be classed as 'abandoned' by the criteria in Table 3 of the 2022 memo are shown as actually 'plugged and abandoned'. Hence, EPA should not ignore the Enverus data in favor of unsupported assumptions.

- API contends that an alternative estimate of historically abandoned wells could be based on data for 'undocumented orphan wells' provided in the 2019 report issued by the Interstate Oil & Gas Compact Commission (IOGCC)[2]. According to the IOGCC 2019 report the total estimated number of undocumented orphan wells reported by the states is between 210,000 and 746,000 (*as shown in Table 1. Total Idle and Orphan Wells: All Surveyed States and Provinces (2018)).*

- API also asks EPA to provide greater insight into the process of restructuring of the Enverus data set and the treatment of dry wells. API notes that the designation of "Dry Wells" in the Enverus database indicate a production type rather than a status type and EPA's approach of considering all wells with no cumulative production as abandoned wells is likely leading to

[1] https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-abandoned-wells_sept-2021.pdf
[2] IOGCC, 2019, Idle and Orphan Oil and Gas Wells: State and Provincial Regulatory Strategies; https://iogcc.ok.gov/sites/g/files/gmc836/f/documents/2021/2020_03_04_updated_idle_and_orphan_oil_and_gas_wells_report.pdf

double counting of dry wells in the abandoned well category since they are embedded in the well status counts. Furthermore, EPA's assumption that dry wells are unplugged is neither consistent with the Enverus data nor State plugging requirements. Current Enverus data shows that 93% of dry holes are plugged. Texas requires the same plugging standards for dry holes as for idle production wells and other State requirements are believed to be similar.

- Many of the largest producing states have regulations in place spelling out emissions, discharge or integrity requirements that must be met when a well is non-producing. API stipulates that the simple assignment of the 'unplugged' designation to all the status codes that are not 'Excluded' or 'Plugged and Abandoned' (P&A) overlooks the potential impacts of such regulations and is therefore inaccurate. Such regulations, even if not directly promulgated to control volatile emissions, have the potential for lower emission rates from wells that are subject to regulation when inactive*. See Appendix 1 for matrix of state requirements for inactive wells.* API is looking forward to engaging with EPA on the impact of existing regulatory requirements on emissions from abandoned and inactive wells.

- API's analysis of Enverus data does not validate the information in Table 3 of the 2022 Abandoned Wells Update Memo as representative of calendar year 2019. However, the counts in Table 3 are broadly similar to API's analysis of current date Enverus well counts. API requests that EPA should validate that their modified query of the Enverus database for 2019 counts is correct and provide this information to stakeholders in an updated Table 3 if changes are substantive.

- Moving forward API recommends that EPA should continue to use the Enverus production type field, where available, to classify wells into gas vs. oil and should also use the Enverus P&A status for determining what dry holes are unplugged. API further recommends that EPA should continue to use the cumulative production coupled with the well status and production type information to determine the count of dry wells*.*

- API is not aware of alternative, high quality, sources of data readily available to inform the count of abandoned wells or the split into plugged and unplugged categories

***Post meter emissions*[3]**

- API acknowledges EPA's proposed intent to add estimates from post-meter residential, commercial, and industrial customer methane emissions as well as certain natural gas vehicle emissions in accordance with guidance provided in the 2019 Refinement to the 2006 Intergovernmental Panel on Climate Change (IPCC) Guidelines for National Greenhouse Gas Inventories for natural gas systems (IPCC 2019).

- API recognizes that while post-meter emissions will be part of the Natural Gas Systems chapter of the GHGI, it requests that the data be provided as its own "line item" within natural gas

[3] https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-post-meter_sept-2021.pdf

systems. It should not be included in the distribution segment, which ends at the customer meter.

- For residential post meter emissions, EPA intends to base its estimate on the Fischer et. al. (2018) report[4], which measured CH_4 leak emissions from 75 homes that use natural gas in California. This study is used as the basis for the estimate provided in the CARB state GHG inventory. API observes that the limited regional nature of the 2018 data used for CARB's estimate is not sufficiently large to represent residential gas use and potential CH_4 emissions nation-wide. In the absence of better data API suggests that EPA consider a bifurcated approach that uses other available regional data, such as the Merrin and Francisco (2019), outside of California.

Use of GasStar and Methane Challenge reductions in GHGI[5]

- EPA is assessing the applicability of reductions reported under GasStar and the Methane Challenge voluntary programs for the accounting of emission reductions data to prevent double counting. API supports EPA's intent to remove the current time series of GasStar emission reductions and replace them with an updated series for the span of 1990-2019 for those sources for which 'potential to emit' methodology is still used in the GHGI estimates.

- API objects to EPA's proposal to revise the GasStar emission reductions dataset by applying sunset dates of 7 or 10 years for those emissions, rather than assume that the reductions are permanent. API members, who are also GasStar partners, contend that sunsetting of the "reductions" in the GasStar program were not necessarily related to any lack of efficacy, or "decay", of the reduction or control measures put in place. Adoption of the sunset dates' methodology reflected the goal of the GasStar program to drive additional reductions overtime. Thus it was the credits offered in the programs that were retired, with no indications that the emission reductions ceased or that emissions increased.

Applying midstream activity data updates[6]

- EPA is considering using the Enverus Midstream and PHMSA data to update certain activity data. This would result in potentially significant changes to counts of processing plants, gathering and boosting compressor stations, gathering pipeline miles, and transmission pipeline miles, with a smaller change to the count of transmission compressor stations.

- API support the continued use of current sources of activity data previously used in the GHGI which relied on data reported through the GHG Reporting Program (GHGRP) and other

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[4] Marc L. Fischer, Wanyu R. Chan, Woody Delp, Seongeun Jeong, Vi Rapp, Zhimin Zhu. An Estimate of Natural Gas, Methane Emissions from California Homes. Environmental Science & Technology 2018, 52 (17), 10205–10213; .https://pubs.acs.org/doi/10.1021/acs.est.8b03217

[5] https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-gas-starmc_sept-2021.pdf

[6] https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-activity-data_sept-2021.pdf

regulatory programs. API does not support moving to the Enverus database without further review and explanation on how the database was developed.

- The current activity data in the GHGI has been developed from regulatory data ensuring alignment of, and achieving consistency with, reported industry data. For example, GHGI 2019 data accounts for 667 natural gas processing plants and represents about a 25% higher count than that available from the EIA 757 survey (479 in EIA, 2017)[7], or the 449 facilities that reported to GHGRP in 2019. This difference may be explained by the regulatory thresholds for the reporting facilities. To compare, the Enverus Midstream database indicates that there are more than double natural gas processing plants (1021 - see Table 6 of EPA September 2021 memo). API is concerned that such a large discrepancy indicates that there might be double-counting of processing plants, which may call into question the reliability of the entirety of Enverus Midstream data.

- API has previously supported the use of PHMSA data for midstream activities and continues to support the use of PHMSA for storage well counts. API affirms that using the PHMSA data uses actual counts versus the current GHGI estimation.

Anomalous Events including Well Blowout and Well Release Emissions[8]

- EPA is considering expanding the estimation of anomalous events from just onshore oil well blowouts to including onshore oil and gas well blowouts and releases. EPA intends to use the existing emission factor and TX RRC extrapolated activity data to estimate blowouts and releases.

- API is concerned over the use of a single emission factor for both oil and gas wells, as well as representing both blowouts and releases. API is seeking more information (with a specific citation) to the "Industry Review Panel" that originally proposed the 2.5 mmcf/event emission factor. API calls on EPA to more precisely distinguish between a well blowout and a well release and explain what the existing distinction is.

- API requests that EPA clarify whether there is a possibility of developing emission factors that are based on the length of the blowout rather than the events count, and further consider whether the TX RRC database can be leveraged to link the activity factor to a set of scaled emission factors, i.e., based on those same qualitative measures by which EPA was able to consider the relative frequencies of blowouts and releases.

- Though API has requested more information regarding the 2.5 mmcf/event EF, API recommends that moving forward for now, EPA continue to apply the current EF (2.5 mmcf/event) to onshore oil well blowouts only. API does not support expanding the use of the current EF to either oil well releases or to natural gas well blowouts and releases without getting

[7] https://www.eia.gov/naturalgas/ngqs/#?report=RP9&year1=2017&year2=2017&company=Name
[8] https://www.epa.gov/system/files/documents/2021-10/2022-ghgi-update-well_blowouts_releases.pdf

more information, better leveraging TX RRC database, or scaling EFs based on event and well types.

- API supports using measured emissions data or engineering estimates for unique major anomalous leak events when they occur. Such major events need to be evaluated on a case-by-case basis, per IPCC guidelines[9].

API welcomes EPA's willingness to work with industry to improve the data used for the national inventory. API encourages EPA to continue these collaborative discussions including making progress in addressing the new data collected by the API field study on Pneumatic Controllers emissions.[10] As indicated before, API is available to work with EPA to make best use of the information available under the GHGRP, or other appropriate sources of information/data, to improve the national greenhouse gas emission inventory. To that end we await hearing about the agency's next steps with regard to incorporating revisions to the GHGRP.

Sincerely,

Marcus J Koblitz

Marcus Koblitz
Policy Advisor, Climate & ESG Policy
Corporate Policy
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cc. Mark DeFigueiredo, DeFigueiredo.Mark@epa.gov

Attach: Appendix 1. Matrix of State and Federal Well Abandonment Programs

[9] 2019 Refinement to the 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 2 Energy, 4.2.2.3 CHOICE OF EMISSION FACTOR1 B 2 a vi Other

[10] API, *Pneumatic Controller Inventory and Measurement at 67 Oil and Gas Sites in the Western United States*, March 2020 (submitted to EPA by memorandum on July 2, 2020)