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January 31, 2022

The Honorable Michael S. Regan, Administrator
US Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

VIA E-MAIL AND E-FILING

Re: Comments on Environmental Protection Agency's Proposed Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review

Docket ID No. EPA-HQ-OAR-2021-0317

Dear Administrator Regan:

The following associations appreciate the opportunity to comment on the aforementioned "Proposal": the Independent Petroleum Association of America (IPAA), Arkansas Independent Producers and Royalty Owners (AIPRO), Domestic Energy Producers Alliance (DEPA), Eastern Kansas Oil & Gas Association (EKOGA), Gas & Oil Association of West Virginia (GO-WV), Illinois Oil & Gas Association (IOGA), Independent Petroleum Association of New Mexico (IPANM), Indiana Oil and Gas Association (INOGA), International Association of Drilling Contractors (IADC), Kansas Independent Oil & Gas Association (KIOGA), Kentucky Oil & Gas Association (KOGA), Michigan Oil and Gas Association (MOGA), National Stripper Well Association (NSWA), North Dakota Petroleum Council (NDPC), Ohio Oil and Gas Association (OOGA), The Petroleum Alliance of Oklahoma (The Alliance), Petroleum Association of Wyoming (PAW), Pennsylvania Independent Oil & Gas Association (PIOGA), Texas Alliance of Energy Producers (Texas Alliance), Texas Independent Producers & Royalty Owners Association (TIPRO), and Western Energy Alliance (Alliance) (collectively, "Producer Associations"). Many of the Producer Associations have been active in all rulemakings since Subpart OOOO was promulgated in 2012.[1]

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[1] Attached and incorporated by reference are the comments filed by IPAA or a subset of the Producer Associations in the informational "open docket" that EPA created prior to this rulemaking, *i.e.*, Docket No. EPA-HQ-OAR-2021-0317, included as "Attachment B". Appendix B to the attached July 30, 2021 filing (in Attachment B) are the comments filed by the majority of the Producer Associations on the October 15, 2018 Reconsideration Rulemaking, Docket No. EPA-HQ-OAR-2017-0483. Footnote 1 to those comments incorporated prior comments made by IPAA or a subset of the Producer Associations and the Producer Associations incorporate by reference the comments listed in Footnote 1 and filed in previous rulemakings related to Subpart OOOO and Subpart OOOOa.

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1. Producer Associations Support the Proposed Retention of Certain 2020 Technical Amendments.

The Producer Associations support the following proposed changes to Subpart OOOOa, promulgated pursuant to the Clean Air Act (CAA) that were revised by the 2020 Technical Rule for volatile organic compound (VOC) controls/requirements which would also apply to controls/requirements associated with methane emissions. The revisions are supported by the record and we agree with the Environmental Protection Agency (EPA) that the requisite revisions to Subpart OOOOa should be made:

- Allow the use of a separator at a nearby centralized facility or well pad that services the well affected facility during flowback, as long as the separator can be utilized as soon as it is technically feasible for the separator to function.

- The separator that is required during the initial flowback stage may be a production separator as long as it is also designed to accommodate flowback.

- Clarification to definition of "flowback" and what is not included in the definition of "flowback."

- Changes and/or streamlining recordkeeping and reporting requirements.

- Expanding the technical infeasibility provision to apply to pneumatic pumps at greenfield sites.

- Clarification that boilers and process heaters are not considered control devices for purposes of the pneumatic pump standards. Nothing has changed within the industry to warrant EPA changing their initial determination.

- Allowing for the certification of technical infeasibility to be provide by a professional engineer or in-house engineer.

- The various changes and clarifications related to closed vent systems. Producer Associations would like to point out the Proposal inaccurately cites previous EPA conclusions with regard to Optical Gas Imaging (OGI) monitoring of closed vent system (CVS) at "no extra cost." The cited reference makes no mention of cost and it is Producer Associations that consultants conducting emissions surveys add equipment to monitor at no extra cost.

- Exclusion of "wellhead only well site" or a well site that later becomes a wellhead only well site from fugitive emissions monitoring. EPA should clarify if the well head is disconnected from the associated tank that the well is removed from the monitoring program.

- Extension of the initial monitoring of methane from well sites and compressor stations from 60 to 90 days.

- Clarification of requirements associated with the delay of repair requirements for fugitive methane emissions at well sites and gathering and boosting compressor stations and fugitive VOC and methane fugitive emissions at compressor stations in the transmission and storage segment.

- Revisions to the definition for startup of production as they relate to fugitive emissions at well sites.

- Exclusion of Class I and II Underground Injection Wells as a "well site" for Subpart OOOOa. EPA should also exclude Class II enhanced recovery wells from the monitoring requirements as well.

- Changes to the alternative methods of emissions limitations (AMEL) provisions.

- Alternative fugitive emissions standards based on equivalent state programs.

- Changes related to onshore natural gas processing plants.

- The "technical corrections and clarifications" present at 86 FR 63168-69.

2. Producer Associations Appreciate That EPA is Reevaluating the Definition of Hydraulic Fracturing.

The majority of producing states and industry acknowledge the difference between "conventional" and "unconventional" wells. EPA accepts the terminology but alleges that it always intended to regulate all hydraulically fractured wells.[2] Many of the Producer Associations have argued since 2011 that the conventional wells have a very different environmental "footprint" than unconventional wells. These associations and individual companies tried to have EPA promulgate a definition of a "low pressure well" that comported with industry knowledge of marginal or stripper wells. In 2015-2016 the focus changed to "low production wells." While the terminology utilized by EPA has changed over the past 10 years, the focus of the Producer Associations has been consistent and steadfast – conventional, vertically drilled wells are fundamentally different than large volume, horizontally drilled unconventional wells and one size does not fit all. It is curious that in the Proposal, EPA's definition of "hydraulic fracturing" contains certain terms or phrases that are vague and/or subjective that casts a very, very broad net. Until the Proposal, EPA has spent little effort to explain what "tight formations" and "high rate, extended flowback" means and perhaps engages in a certain amount of "back filling" to justify casting such a broad net.

The Producer Associations suggest the definition of hydraulic fracturing be clarified to include the following objective and supportable/measurable criteria:

[2] EPA cites various docket materials to support their assertion at footnotes 327 through 333. Most of the footnotes cite to Docket ID Item Nos. EPA-HQ-OAR-2010-0505-0445, EPA-HQ-OAR-2010-0505-05021, and EPA-HQ-OAR-2010-0505-07632. Certain representatives of the Producer Associations searched on multiple occasions for these docket materials and they were not available for review. It is difficult to evaluate the accuracy of EPA's assertions when the cited materials are not available to the general public for review.

- Flow back time: any well that has a flowback period of greater than three days is considered to be an extended flowback. This threshold is consistent with EPA's estimate that the minimum flowback period for high volume fracture stimulation events is at least three days.

- Tight formation: any formation that has a permeability that is less than one thousandth of a Darcie (0.001) should be considered to be a tight formation.

- Volume: any well utilizing greater than 100,000 pounds of proppant and/or more than 1,000,000 gallons of water is considered to be high volume used to stimulate the formation.

3. EPA's Consideration of "Community and Environmental Justice Implications" of the Proposal Needs to Include the Impacts on Rural Communities that are Underserved and Overburdened.

EPA's Proposal dedicates extensive discussion to ensure "robust and meaningful public engagement" with "underserved or overburdened communities." EPA focuses on the "particularly vulnerable to the climate and health impacts of pollution from this source category."[3] The Producer Associations completely support such effort. The Producer Associations remind EPA that in many rural areas of this country that "this source category" is not simply something defined by the CAA but it is their livelihood – it allows them to heat their homes and hopefully stay above the poverty level. A drive through many areas of rural America in producing states quickly illustrates that many, many communities depend on this "source category" for their existence. The workers of this source category and their families live and breathe in close proximity to these emissions sources – they care what is being emitted. EPA's Proposal represents a real threat to these rural communities. Homeowners and farms often rely on the gas from wells located on their property or pipelines that transverse their property to heat their homes and/or provide critically important income.

Beyond the homeowners and farmers that directly rely on gas from wells on their property and/or pipelines that transverse their property, there are many communities that rely exclusively on gas supplied by low production/marginal wells located geographically close to their homes and would not be served if certain low production wells are shut-in because the small, local oil and natural gas company cannot afford to comply with the regulations in the Proposal. While the citizens of these rural parts of the country are certainly concerned with the "climate and health impacts of pollution from this source category" – they are also concerned with their livelihood and putting food on the table. The potential impacts of the Proposal extend well beyond the operators in this "source category." Consideration of the impact to the numerous "mom and pop" companies selling gas, food, lodging, etc. that rely on this source category needs to be factored into the "environmental justice implications" of this Proposal in order to constitute "meaningful engagement" of "underserved and overburdened communities." This Proposal crunches numbers to support "cost-effective" controls. EPA also engages in an interesting discussion of what constitutes the "best system of emission reduction" (BSER) and the "cost" of achieving such

[3] 86 FR 63115 (Nov. 15, 2021).

reduction.[4] Describing or defining what is "reasonable" as something not "exorbitant" and not something "greater than the industry could bear and survive", by individuals that in most cases have never been to these rural areas of the country is not overly comforting to the members and their dependent families of the Producer Associations. The Producer Associations support EPA's efforts to go beyond the numbers and to better under the real impact of this Proposal on rural populations of this country.

4. EPA's "Pathways" to More Community Involvement and Monitoring Need to Address Issues Associated with Safety, Trespass and Data Validation.

The Proposal solicits comments on "a pathway for communities to detect and report large emitting events that may require follow-up and mitigation by owners and operators."[5] The Producer Associations have safety and trespass concerns associated with EPA encouraging community involvement in monitoring operations and request that EPA make clear that property boundaries must be respected and highlight the dangers present at certain oil and natural gas operations. The individual companies engage in extensive safety training and equip their employees with equipment to help protect them from the dangers that are often present at oil and natural gas operations. The Producer Associations are also concerned with the consideration of requiring owners/operators to respond to "large emission events" without placing certain requirements on the validity and veracity of the data being provided by community monitoring. Owner/operators are subject to extensive recordkeeping and reporting and the proposed Appendix K greatly expands what companies must do to validate their information. Similar requirements should be placed on the owner/operator of the community monitoring equipment and data – "what is good for the goose is good for the gander." The general public should not be able to utilize unverified or inaccurate data to force owner/operators to interrupt operations and provide responses. Additionally, the general public is not trained to understand the operations of the facilities to differentiate between a "leak" and an emission event that represents normal operations, a permitted event and/or necessary for safe operation. Producer Associations are not objecting to community monitoring, but suggest there are significant safety concerns for the general public; privacy/trespass issues; and fairness/accuracy issues associated with emissions "data" being presented to regulators and requiring operators to response to poor, inaccurate or specious data.

5. Comment Period is Inadequate and the "Applicability Date" is Not November 15, 2021.

On November 15, 2021, EPA published a "proposed rule" regarding "Standards of Performance for New, Reconstructed, Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review". 86 FR. 63110. The document is characterized as a proposed rule, yet the 154 pages of Federal Register text contain no proposed regulatory language. The "proposed rule" is not a proposed rule, at best it is an "advance notice of proposed rulemaking."[6] At the request of the Producer Associations and other stake holders, EPA provided roughly an additional 14 days for comments. While the Producer Associations

[4] 86 FR 63133 (Nov. 15, 2021).

[5] 86 FR 63115 (Nov. 15, 2022).

[6] https://www.reginfo.gov/public/jsp/eAgenda/Abbrevs.myjsp

appreciate the additional time, the comment period is still inadequate. EPA submitted a memorandum and table to the docket on or about November 1, 2021, that attempts to summarize the various issues EPA is seeking input on: the table, in small font, is 28 pages long.

There is no statutory deadline forcing a truncated comment period. Additionally, at the Producer Associations pointed out in their request for additional time to comment, the Department of Energy (DOE) is poised to produce a study on emissions from low production wells that needs to be reviewed and considered by EPA as it intends to withdrawal certain exemptions for low production wells.[7] The truncated comment period, when EPA is aware of the pending DOE study, is arbitrary and capricious.

EPA states that "methane and VOC emissions from sources that commenced construction, modification, or reconstruction after November 15, 2021" will be required to comply with the proposed "requirements."[8] The applicability date (the requirements of the NSPS apply to any sources constructed or modified after a certain date) is the date of the NSPS are proposed and published in the Federal Register. As indicated above, the November 15, 2021 publication in the Federal Register contains no proposed regulatory language at all. For EPA to state that all new or sources modified after November 15, 2021 are to be subject to yet drafted regulations is arbitrary and capricious.

6. Simplify Applicability Dates for Regulators and the Regulated

As discussed above, while November 15, 2021 is not an appropriate "effective date" for any NSPS that comes from this regulatory action, EPA needs to recognize and account for the significant financial investments industry has made to comply with requirements of Subpart OOOO and Subpart OOOOa as it looks to regulate "existing sources" under OOOOc. While EPA disclaims it is directly regulating existing sources under Subpart OOOOc to avoid certain regulatory/statutory obligations,[9] the reality is EPA has very little intention to accept anything other than the standards and requirements it intends to finalize as "guidelines."[10] Ostensibly, once EPA actually provides proposed regulatory language sometime in 2022, everything prior to that date will become an "existing source" and ultimately required to comply with Subpart OOOOc. As Subpart OOOOc is generally more stringent that Subparts OOOO and OOOOa, the regulated industry will, in certain instances, be required to rip out recently installed control devices in order to comply with the new, more stringent requirements of Subpart OOOOc. The cost-effectiveness of controls under Subpart OOOO and Subpart OOOOa assumed a certain life cycle/time to obtain the benefits of those controls. Subpart OOOOc threatens to undermine the cost-effectiveness justification of those controls by requiring new, more stringent controls in the relative near future.

[7] Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells - Draft Final Project Report, US DOE NETL Award Number DE-FE0031702 (Dec. 31, 2021) - "Attachment C".

[8] 86 FR 63116 (Nov. 15, 2021). The timing of the "proposal" may have influenced the characterization of the document as the current Administration headed into the 26th UN Climate Change Conference of the Parties in Glasgow from October 31 through November 13, 2021.

[9] Attached is a copy of the Small Entity Representative Pre-Panel Outreach, June 2021, slide 16 - "Attachment D".

[10] "Given these facts, the EPA believes that it would likely be difficult for States to demonstrate that the presumptive standards are not reasonable for the vast majority of designated facilities." 86 FR 63251 (Nov. 15, 2021).

In addition to the problems mentioned above, sources constructed or modified after September 18, 2015, will most likely be subject to Subpart OOOOa and Subpart OOOOc as an "existing source." Such potentially duplicative regulation of the same source will create confusion for regulators and the regulated community. It will also likely impose duplicative record keeping and reporting. To the extent Subpart OOOOc requirements on affected facilities are more stringent than Subpart OOOOa, EPA must demonstrate the additional reduction in emissions is achieved cost-effectively.

A simple fix for this problem would be for EPA to define a designated facility under Subpart OOOOc as being constructed before September 18, 2015. If EPA is willing to exercise this simple solution, EPA needs to take into account the new, more stringent controls EPA's cost-effectiveness evaluations under Subpart OOOO and OOOOa – perhaps having an extended, phased in control period for sources that installed controls pursuant to Subpart OOOOa.

7. It Appears EPA is Attempting to Reduce Flexibility Provided by the CAA Under Section 111(d).

EPA's Proposal creating Subparts OOOOb and OOOOc would change the NSPS and EG process to arbitrarily and inappropriately create an adverse regulatory structure intended to use the CAA to circumvent cost and energy considerations required by Section 111 and avoid consideration of differences in existing and new sources and remaining life issues in Section 111(d).

When the CAA addresses regulations of stationary sources, including facilities that emit air pollutants, the definition of those facilities significantly affects the nature of the regulations. For most petroleum related industry segments, EPA has defined the facility as the entire operation, such as a refinery, or key process units within it, such as a fluid catalytic cracking unit. These facilities are comprised of multiple pieces of equipment such as process vessels, separators, the piping that connects them and valves, flanges, and other component parts. Petroleum storage tanks are an exception because these large tanks are significant potential emissions sources that can be logically distinguished within the refinery or are in stationary sources comprised of storage tanks only.

When EPA has defined a "drilling and production facility" in other NSPS subparts, it has reflected this reality by stating:

> Drilling and production facility means all drilling and servicing equipment, wells, flow lines, separators, equipment, gathering lines, and auxiliary nontransportation-related equipment used in the production of petroleum but does not include natural gasoline plants.)

This historical use of the term facility reflects the reality that an industrial operation is comprised of component parts to produce products for a subsequent purpose. The concept of a facility in the oil and natural gas production segment of the industry is well known; it is a well site. However, in trying to define a well site in the regulatory context, the diversity of the industry creates a challenge. Some simple well sites are only a well head and some control components. More complicated well sites contain process vessels, such as separators, and contain storage tanks. Other well sites may be separated from storage tanks that are intended to serve multiple wells. New non-conventional oil and natural gas well sites may contain multiple wells – 10 to 60 – with common processing equipment and storage tanks while older well sites may be comprised of one or two wells.

In fact, in the supporting documents for this proposal, EPA uses the well site concept for its analyses. In the Regulatory Impact Analysis for pneumatic controllers, EPA states:

> The affected facility for pneumatic controllers is the site, such that any well site, compressor station, or processing plant with pneumatic controllers is treated as a single affected facility, no matter how many controllers are on the site.

In the Technical Support Document, EPA admits that it must look at pneumatic controllers in the context of model well sites to assess the design and cost effectiveness of its proposal:

> Applicability of both the 2012 NSPS OOOO and the 2016 NSPS OOOOa are based on an individual pneumatic controller. However, some of the control options discussed in section 8.4 are more appropriately evaluated as "site-wide" controls. While individual natural gas-driven pneumatic controllers can be switched to other types of natural-gas driven pneumatic controllers (*e.g.*, high bleed to low bleed types), the implementation of some options requires equipment that is used for all the controllers at the site. For example, in order to utilize instrument air driven controllers, a compressor and related equipment would need to be installed. The EPA does not believe that a compressor would be installed for a single controller, but rather to provide compressed air to all the controllers at the site. Therefore, to adequately account for the costs of the system, including the controllers and the common equipment, we developed "model" plants. The model plants were developed based on information reported in several studies suggesting that most well sites have less than 10 pneumatic controllers (45-50 percent have 1-3 pneumatic controllers, 35-45 percent have 4-10 pneumatic controllers, 7-10 percent have 11-20 PCs, < 10 percent have 20+ PCs). We assumed that well site controller numbers would apply to both production and transmission and storage sites.

It is unclear to the Producer Associations why EPA proposes to shift away from these common and well understood concepts of oil and natural drilling and production facilities.

a. Existing Sources Are Not New or Modified Sources and the Standards Should Reflect That Reality.

EPA seems intent on defining "affected" facilities and "designated" facilities in a manner that does not comport with common sense and effectively allows EPA, in almost every situation to define an existing source the same as a new or modified source. This is clearly not the intent of the CAA. EPA has chosen to create an array of confounding definitions that appear to circumvent the intent of the NSPS and EGs.

EPA has used the definition process for "affected facility" – and looking forward to the EG definition of "designated facility" – as a mechanism to parse a well site into components to avoid cost effectiveness tests and impose an unreasonable burden on existing operations. The Subpart

OOOO and OOOOa address numerous elements of oil and natural gas production – pneumatic controllers, pneumatic pumps, storage vessels, compressors, leak detection and repair. While all of these are essentially components of a well site, EPA uses different definitions of affected facility for each of them. EPA is proposing expansion of the oil and gas production facilities NSPS (Subpart OOOOb) and existing source emissions guidelines under Section 111(d) (Subpart OOOOc) that will use still more definitions of components of well sites rather than well sites.

The implications for existing facilities threaten their existence. Section 111(d) provides EPA with the authority to create emissions guidelines to regulate existing sources with air emissions that are neither criteria pollutants nor hazardous air pollutants and are subject to NSPS requirements. When Section 111(d) was created, it was expected to apply to a small number of industries with a limited number of facilities. When courts concluded that greenhouse gases – *e.g.*, carbon dioxide, methane – could fall under the scope of the CAA, it opened a pathway for regulation that can encompass substantial numbers of facilities. Oil and natural gas production facilities emit methane in addition to VOC and there are approximately one million existing oil and natural gas wells. Approximately 750,000 of these wells are low production facilities that are economically at risk.

Section 111(d) of the CAA provide EPA with the authority – in large measure, the mandate – to distinguish between new and existing operations as well as the use of subcategorization for existing sources to reflect their diversity. Past use of Section 111(d) has recognized the reality that new sources differ from existing sources, particularly in the economic implications of burdening these facilities. Much like the Reasonably Available Control Measures concept in Nonattainment, Section 111(d) regulations reflect the need to manage existing facilities differently.

Section 111(d) also provides states (and the federal government) with the authority to provide different requirements for existing sources or categories of sources based on their remaining useful life. This capacity allows states to recognize the different circumstances affecting the facilities in their states. Oil and natural gas production operations differ between states and within states depending on the nature of the production areas and the age and size of these operations.

EPA has indicated it will be revising the regulations to implement Section 111(d).[11] Revision is necessary to implement Section 111(d) because the regulations promulgated in 1975 are outdated and don't comprehend the complicated state regulatory process that has evolved since then. EPA's plan to revise the implementing regulations to Section 111(d) will be far more expansive than a mere update to the time to develop and implement regulations. It will likely include new environmental justice and community enforcement initiatives. EPA also shows its intent to restrict states' ability to use the remaining useful life authority guaranteed by the CAA.

EPA has crafted its NSPS and EG facility definitions to limit the use of subcategorization. The oil and natural gas production industry is by its nature highly subcategorized – large versus small production rates, oil versus natural gas dominated production, oil with associated gas, natural

[11] 86 FR 63134, fn. 95; 86 FR 63251; 86 FR 63254 (Nov. 15, 2021).

gas with natural gas liquids, simple wellheads to multiple wellheads with associated storage tanks, separate tank batteries. These differences can directly affect the amount of emissions at a facility.

The practical result of EPA's use definitions of "affected facilities" and "designated facilities" is that in almost all circumstances the controls required by Section 111(b) are the same as those being required by Section 111(d). That, simply does not make sense to anyone that has built a new facility versus trying to retrofit an existing one - and prior to this Proposal, EPA has generally recognized the difference – if for no other reason – Congress did. The Proposal seems designed to limit the states ability subcategorize the oil and natural gas production facilities. This facility characterization prevents true assessments of the cost effectiveness of the regulations. Consequently, as "proposed" the regulations could easily impose such significant costs on small businesses that compliance will force them out of operation without any meaningful environmental benefits. The CAA built in additional considerations for regulating existing sources under Section 111 and the Regulatory Flexibility Act build in protections for small businesses. EPA's Proposal (and future changes to Section 111(d) regulations) should not eliminate those considerations and that flexibility.

8. EPA's Approach to Regulating Pneumatic Controllers Prevents Realistic Assessments of its Cost Effectiveness and Undermines the Intent of Section 111(d).

The logical facility for oil and natural gas production is the well site. EPA has chosen to define the "affected facility" for regulation of pneumatic controllers as the individual pneumatic controller. While this narrow definition had little impact in the context of Subpart OOOO because it involved the selection of low bleed pneumatic controllers instead of high bleed controllers at new well sites, its expansion to existing facilities through Section 111(d) presents devastating consequences for small business, low production wells.

EPA's proposal would require all pneumatic controllers – low bleed, high bleed, and intermittent bleed – to be eliminated at new sources. Valve control will be managed through electric controllers or instrument air systems. This approach is more costly (instrument air) and pushes the feasibility of some technologies (electric controllers). EPA's cost effectiveness analysis is based on cost per unit of methane reduced rather than the cost to the production at the well site.

EPA then concludes that the same definition applies to existing facilities. Regulatory cost effectiveness for existing facilities is a different task than for new facilities. New facilities have the ability to design in the planned technologies. If they are unaffordable, the project will be terminated. Existing facilities must operate within their current circumstances. This is particularly significant in the oil and natural gas production industry where declining production is an inherent aspect of their operation. When their operations produce small amounts of daily product, expecting these facilities to have the capacity to absorb significant capital expenditures is unreasonable. A cost effectiveness calculation based on recovered emissions does reflect the true burden on a small business, low production well.

To put this issue in some perspective, it is essential to understand the nature of small production wells and small producers. The average low production natural gas well in the US produces about 22 mcfd, but in many states it is far lower. For example, the average low production well in Pennsylvania is 6 mcfd. Nationally, natural gas prices are currently about

$4.00/mcf, although for the past several years, they have been closer to $3.00/mcf. From this gross price, approximately 25 percent goes to royalties and taxes. Operating costs for low production wells are on the order of $2.33/mcf with general and administrative costs of about $3.00/well. These low production wells are always economically challenged. At $4.00/mcf, a 6 mcfd well makes about $1/day and a 22 mcfd well about $12/day. Correspondingly, at $3.00/mcf, a 6 mcfd well loses about $3.50/day and a 22 mcfd well about $4.50/day.

EPA recognized in the Technical Support Document (TSD) for its proposal that existing source small facilities would not be utilizing instrument air controllers and determined controller options based on electronic controllers from either an electric grid or solar power. EPA's estimated costs for these systems for small facilities are $25,494 for the electric grid option and $28,171 for the solar powered option. While EPA presents its cost effectiveness assessment in the context of cost per unit of recovered methane and/or VOC, it is clear that the real impact on a small well site would be overwhelming. Even at the current prices for natural gas, it would take the average low production natural gas well about 6 years of all of its profits to pay for the electric grid option and more than that for the solar option. For a Pennsylvania well site, the time period would be 70 or more years.

Current information does not support a conclusion that pneumatic controllers at low production wells present a substantial contribution of methane emissions. Actual emissions measurement by both environmental groups and during the DOE Project, *Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells* (DOE Project)[12] has shown little if any emissions from process equipment at well sites. Analyses of low production well sites largely show that the primary sources of low production well methane emissions are storage tanks and, in some areas, separator vessels. An emissions control strategy should be targeted at emissions sources where the realistic reductions can be made. The arbitrary decision to duplicate the removal of current pneumatic controllers from existing well sites, particularly low production well sites, is not justifiable.

EPA's justification for requiring wholesale replacement of zero bleed controllers and the supporting equipment will likely generate supply chain shortages and the small operators will be last to procure the necessary equipment at the highest price. While not requiring instrument air for all compressors, EPA's proposed alternatives, *e.g.*, on site power generation or solar fails to reflect the real limitations present at many sites. On site generation of power generates emissions that offset or at least reduce the benefit of requiring zero-bleed controllers. Many basins simply do not have enough solar to reliably provide the power to run the controllers. In many instances, the controllers are in place to address an over-pressurized and unsafe environment on the facility. While operators can build in redundancy features to back up solar, the Producer Associations questions of the cost of those redundancy components are factored into the cost-effectiveness. As many of the Producer Associations have been saying, on various aspects of the NSPS since 2011, one size does not fit all and this represents an example that what may be cost-effective for certain operations will likely not be cost-effective for smaller facilities, often disproportionately adversely impact small businesses.

[12] *Supra* note 7.

EPA's Proposal to define each natural gas-driven intermittent vent pneumatic controller as an affected facility at all types of sites, and require zero emissions from both continuous bleed and intermittent vent controllers is not justified. In 2014, the Oklahoma Independent Petroleum Association [13]conducted a Pneumatic Controller Emissions Study across Oklahoma. The results of the study showed that 17 of 77 controller models identified, were backpressure controllers (accounting for approximately 40% of controllers observed) that are often used for overpressure protection that rarely actuated when encountered during field observations. The average controller count per site was higher by 2.2 for new sites as compared to older sites due to increased process units at the newer sites. The study also found that intermittent vent controllers emitted on the average 0.047 tons/year of methane. The results of this study were compared with the existing body of work on emissions from these types of controllers and found that the other studies overestimated emissions by a factor ranging from 5.4 to 27.5. This information indicates that intermittent pneumatic controllers are not an issue and should not be regulated - certainly not at a zero emission rate. It is not reasonable, cost effective or efficient for operators, especially marginal/low production well operators to now replace these intermittent vent controllers or retrofit their sites to use air-driven, solar, electric or self-contained controllers. In addition, many of these options are not feasible, reliable, safe or economic for all sites. EPA should remove this requirement for zero emission intermittent vent controllers.

9. EPA's Storage Tanks Emissions Assessment is Excessive.

EPA's evaluation of storage tanks is predicated on a number of projections and assumptions that are challengeable. EPA's data source for tank emissions relies on an array of approximately 100 tanks created for the 2012 Subpart OOOO regulations. EPA develops emissions estimates for these tanks using the API E&P Tanks program assuming a 500 b/d throughput and dividing the tank list based on API Gravity to define condensate and crude oil. EPA adjusts the tank emissions projects based on flow rates for different size categories. EPA develops a tank inventory based on a ratio of a baseline production value scaled to a projected future value related to total US production. EPA projects the number of current wells with and without Subpart OOOO controls. These actions become the framework to justify its regulatory actions.

The estimates are suspect. EPA's tank estimates are based on assumptions that more production drives more tanks. While this is valid at some level such as new, unconventional oil and natural gas development, low production well sites, particularly in developed basins will use existing tanks where capacity is available. It is difficult to address the validity of all of EPA's assumptions without access to it various referenced source and many are not readily available. However, it is apparent that EPA relies on estimates based on ratios from total production volumes to project the number of tanks in different size categories. For example, EPA uses condensate production reported in the GHGI. Using this approach, EPA states:

> The 2019 GHGI data indicated that condensate production increased from a level of 145 million barrels per year (MMbbl/yr) in 1992 to 454 MMbbl/yr in 2019 (approximately 288 percent). This 288 percent increase in condensate production was distributed across the model condensate tank batteries in the same proportion

[13] Oklahoma Independent Petroleum Association merged with the Oklahoma Oil and Gas Association to form The Petroleum Alliance of Oklahoma which one of the Producer Associations submitting these comments.

> as was done for the NESHAP HH rulemaking. Based on this approach, it was estimated that there was a total of 36,501 existing condensate tank batteries in 2019.

Other information would produce very different results. For example, the EIA has developed extensive data on oil and natural gas production by size of well. Comparing comparable years, 1992 and 2019, The EIA data would show a different pattern. The following table displays key information:

	1992	2019	
Production Range (BOE/d)	Natural Gas Condensate (MMBbls)	Natural Gas Condensate (MMBbls)	Percent Change
≤10 BOE/d	15.6	17.248	10.6
≤15 BOE/d	23.1	26.492	14.7
≤50 BOE/d	55.3	78.261	41.5
Total	393.9	576.153	46.2

This table shows that condensate production did not increase by 288 percent; instead, it increased by about 46 percent. It also shows that for smaller wells, production changes were on the order of 10 to 15 percent – far less than the total increases.

EPA makes a similar error with regard to crude oil in estimating the number of new tank batteries:

> Using the assumption of four tanks per tank battery (as shown in Table 6-1), the EPA scaled the 2006 crude oil storage vessel population to represent 2019 crude oil tank batteries using a ratio of the 2019 and 2006 crude oil tank throughput values from the 2019 GHGI. According to the 2019 GHGI, crude oil throughput increased from 1,679 MMbbl/yr in 2006 to 4,666 MMbbl/yr (an increase of approximately 278 percent) in 2019.

Using EIA information from 2006 and 2019 the following table shows a different result:

	2006	2019	
Production Range (BOE/d)	Oil (MMBbls)	Oil (MMBbls)	Percent Change
≤10 BOE/d	206.5	196.555	-4.8
≤15 BOE/d	285.0	274.916	-3.5
≤50 BOE/d	588.0	640.126	8.9
Total	1,643.0	3901.859	137.5

For crude oil, the information is more striking. While crude oil production increased by 137.5 percent, production for smaller wells actually decreased.

This information calls into question EPA's fundamental assessment that tank construction is producing the substantial numbers of new tanks. In particular, using total production increases as a basis to scale up tank numbers is inherently flawed. True, oil and natural gas production has increased over the past fifteen years primarily because of shale oil and shale gas production. However, production from small wells has been essentially flat. Therefore, tanks related to smaller operations would not be constructed in any significant amounts. Because of natural depletion, existing tank batteries will have excess capacity that can be used by new wells. These actions will not result in emissions beyond the original design.

EPA can develop emissions management strategies that do not require vapor capture for lower emissions tank batteries. Data collected by GSI, and even environmental groups, show that significant emissions sources at tank batteries are open thief hatches and deteriorated seals around tank openings. These emissions points can be addressed through routine operational and maintenance programs.

10. EPA's Proposed Changes Related to Storage Vessels Need Clarification.

EPA's proposes, under Subpart OOOOb, to include a tank battery as a storage vessel affected facility. EPA then goes on to propose a tank battery is defined "as a group of storage vessels that are physically adjacent and that receive fluids from the same source . . . or which are manifolded together for liquid or vapor transfer."[14] The Producer Associations primary concern with this suggested definition is the use of the term "adjacent." Both EPA and Title V air sources are more than familiar with the challenges and problems with defining and understanding what "adjacent" means. As an alternative to opening Pandora's Box via inclusion of "adjacent" in the definition, the Producer Associations, recommend that the definition be simplified to mean a group

[14] 86 FR 63178 (Nov. 15, 2021).

of storage vessels that are manifolded together for liquid transfer – it need not be more complicated.

11. EPA's Leak Detection and Repair (LDAR) Proposal has Useful Elements but Needs Revision to Make it Cost-Effective for Smaller Existing Sources.

Unlike other elements of the EPA proposal, the LDAR provisions are based on equipment within the well site. EPA proposes to base its LDAR requirements on the emissions rates of fugitive emissions – suggesting three categories: three tons/year or less, three to eight tons/year and greater than eight tons/year.

While this concept is appropriate, several key issues need to be understood:

a. The basis for the thresholds;

b. The scope of components that comprise the fugitive emissions baseline; and,

c. The validity of the emissions estimates for the fugitive emissions components.

EPA's basis for selecting its thresholds is thinly based on assumptions related to the cost effectiveness of its OGI LDAR requirements that are debatable.

EPA's scope of components for the fugitive emissions program must be consistent with its other requirements and reflective of the validity of its emissions estimating tools. EPA is correct in excluding individual wells from the well site definition for the LDAR program. EPA should similarly exclude individual wells from its other regulatory requirements. EPA is creating specific requirements for numerous components of the well site. These components should not be included in the fugitive emissions calculations, in part because Subpart W emissions factors would not reflect their emissions. These include pneumatic controllers, pneumatic pumps, and storage tanks.

Introduced in the context of fugitive emission components, EPA introduces and proposes the results of emissions surveys to require a root cause analysis. EPA cites no authority for requiring such analysis by industry. Respectfully the Producer Associations believe their individual member companies are in the best position to determine when a root cause analysis is necessary and what that analysis should entail. Adding additional reporting and recording keeping associated with some vague, undefined concept of "root cause" is as best tangentially related to potentially reducing emissions at some point in the future. Introduction of requirements that address "root cause" are more properly addressed by OSHA and process safety management.

Before EPA implements these new requirements, particularly for low production existing wells, it must validate its Subpart W emissions estimating factors. The Subpart W emissions factors were not developed for the purposes for which they are now being used. GTI's development of these factors in the mid-1990s was never intended to be used for the GHG inventory calculations and certainly not for regulatory compliance or taxation. A typical Subpart W emissions factor is based on a limited number of facilities using technology that may be well out of date. It is also structured to reflect both normal and failed equipment operations and thereby includes factors to reflect the fat tail aspect of oil and natural gas production operations.

The emissions factor for intermittent pneumatic control valves is a case in point. EPA is expanding its scope of pneumatic controller regulation in this proposal to include intermittent controllers – controllers that emit when they are activated. Part of EPA's justification for this action is the high Subpart W emissions factor for these controllers. This emissions factor resulted from work by the Gas Technology Institute (GTI). The factor is 13.5 scf/h. It is based on 19 intermittent controllers most of which were in Canada. Subsequent studies by Oklahoma Independent Petroleum Association (not the Petroleum Association of Oklahoma) and EPA of US intermittent controllers, many of which were on low production wells have produced emissions factors far lower than the Subpart W factor – 0.4 scf/h (OIPA) and 0.32 sdf/h (EPA). Yet, EPA still uses the GTI factor for the Subpart W GHG reporting and presumably for its proposed emissions calculations justifying its new proposal.

Millions of dollars will be spent on compliance with these LDAR requirements (and on replacement of intermittent pneumatic controllers); the requirements should not impose these costs when the environmental benefits are specious. Among the most vulnerable operations to be burdened by these regulations with be low production wells – the primary target of the environmental groups determined to "keep it in the ground." Recent work for a DOE Report shows that the low production wells that it measured and evaluated would overwhelming fall below the EPA proposed 3 tons/year threshold. It is imperative that EPA's Subpart W emissions factors are as accurate as these field tests.

EPA is proposing with no explanation or justification that the total site-wide calculations be re-calculated every time "equipment" is added or removed from the site. This might, might be justified if equipment that increases the site's PTE over the original design. Requiring another expensive calculation when equipment is removed is an unjustified expense with no environmental benefit. EPA further seeks comment on whether sites should account for PTE and/or a factor that accounts for large emissions events. Baseline emissions calculations should be representative of normal operations, not large emissions events. The EPA seems to allow for sites with calculated baseline emission less than 3 TPY be exempt from surveying obligations and then makes every effort to make it such no sources will be able to demonstrate baseline emission below 3 TPY. To the extent low production wells are required to calculate baseline emission, the calculation should be a calculation of fugitive emissions, *i.e.*, leaks.

12. EPA Should Develop its OOOOc Emissions Guidelines Based on Well Sites and Normal Emissions Patterns.

The predominant impact of OOOOc will be on low production well sites and their associated facilities. EPA has identified its view of low production well sites in the LDAR proposal as facilities emitting 3 tons/year or less of methane. In other facilities, EPA has used different thresholds, such as 4 tons/year of VOC for storage tanks or 6 tons/year of VOC for storage tanks or 20 tons/year of methane for storage tanks. These thresholds reflect various cost effectiveness assessments. Key to the analysis of emissions is the quality of emissions estimates – an issue where EPA's materials are suspect.

a. Fugitive Emissions

EPA's proposal to eliminate the low production well exemption and require all sources to calculate baseline emissions is extremely problematic for many small businesses and operators.

EPA's continued emphasis on component counts over throughput and operating pressure in determining the amount of fugitive emissions fails to recognize basic physics. Almost all emissions calculations are based on throughput but to then discount throughput when evaluating fugitive emissions simply does not make sense. The Producer Associations are not disputing that component count does have an impact on emissions – the more pieces of equipment connected together increases the chances for leaks – but the Producer Associations continue to argue that production rates and pressure play a significantly more important role in fugitive emissions.

The DOE Report has shown that most low production well sites (15boe/d and less) emit less than 3 tons/year of methane based on actual measurements. At issue is whether these measurement results would compare with the Subpart W calculation in EPA proposal for the same facilities. The well site definition should be based on the common facilities at a well site that are not separately regulated under OOOO, OOOOa, or OOOOb. For example, tanks/tank batteries and liquid unloading operations should not be part of the well site emissions determination.

While the Producer Associations believe that a low production well definition is a far simpler method that produces comparable results, on the basis of the above well site definition and the use of accurate emissions factors, the Producer Associations can accept the concept of using a 3 ton/year low production facility exclusion from the quarterly LDAR program but recommends an annual AVO (audio, visual, olfactory) review rather than the OGI EPA program.

However, it is essential that EPA recognize that most of the well sites falling below 3 tons/year will be operated by small businesses and small businesses that are unaccustomed to calculating methane emissions. Consequently, EPA needs to develop, in concert with the Small Business Administration, a straightforward guideline document that operators could use in determining whether a site is below 3 tons/year of methane. This guideline document should be developed prior to the planned supplemental proposal for Subparts OOOOb and OOOOc and subject to comments during that proposal.

To elaborate on this issue, while EPA lays out a conceptual approach to determine site emissions using available Subpart W emissions factors and other estimating tools, small production operations have no familiarity with these tools and the subtleties of their application. If EPA continues to reverse its position on the use of production rates to define a threshold to recognize lower regulatory requirements, it should recognize that the DOE Report provides data showing that these well sites overwhelming fall below the 3 tons/year of methane emissions based on actual sampling. Moreover, the framework that the DOE Report created in defining the factors that can influence emissions – *e.g.*, production rate, oil or natural gas production, number of piece of equipment at the site – could provide EPA with a framework for the development of an emissions calculation guideline for small businesses and low production well sites.

b. Pneumatic Controllers

The concept of using a well site emissions threshold is appropriate to creating more cost effective regulations for low production well sites and should be expanded to other components. Pneumatic controllers are an appropriate example.

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EPA's actions to separate these inherent components of oil and natural gas production well sites from the other components of the well site is an arbitrary act to avoid the reality that existing operations differ from new ones. EPA's envisioned new requirements for pneumatic controllers involve substantial investment such as an instrument air system that needs multiple pneumatic controllers in order to make it cost effective or electronic controllers requiring on site power or solar power. Low production operations have limited numbers of pneumatic controllers and are frequently located in remote areas without access to power. EPA has recognized these realities in the past.

In the context of Section 111(d), EPA needs to recognize these distinctions and provide for different requirements. EPA should exclude low production well sites emitting 3 tons/year or less from the scope of its emission guidelines for pneumatic controllers. Alternatively, EPA should provide for a threshold number of pneumatic controllers to be present at a well site before the pneumatic controllers requirements are applied, a threshold that reflects the cost effectiveness of the requirement based on the ability of the well site to absorb the cost.

c. Storage Tanks

EPA uses a similar threshold concept for storage tanks but needs to have a more realistic approach for OOOOc. EPA has already made determinations regarding the threshold for vapor capture regulations for new sources – 6 tons/year of VOC – and for existing sources – 20 tons/year of methane. It similarly recommended a 6 tons/year of VOC threshold for existing tanks in its October 2016 Control Techniques Guidelines (CTG) for ozone nonattainment areas. However, its proposal for changing the modification threshold based on new production directed to a tank battery creates unnecessary complications based on poorly understand industry practices.

As described previously, EPA's analysis of the number of uncontrolled tanks significantly overstates the number of these tanks and appears to drive EPA's actions to expand its controls, particularly for smaller tank batteries. Because tank batteries are designed based on the initial production from a grouping of oil or natural gas well sites, they will later operate at a throughput well below their design rate. It is common industry practice for wells to be redirected to different tank batteries to consolidate operations – which can reduce the number of operating tank batteries. These wells may be new or existing wells. At low production well sites, these redirected wells are frequently low production wells, but regardless will deplete further over time.

EPA acknowledges that applying vapor capture to existing tanks is more costly and can confront structural challenges compared to new tanks. It also acknowledges that the cost effectiveness for regulating methane emissions from storage tanks differs from VOC and set the emissions threshold at 20 tons/year.

EPA's new definition of modification triggers a convoluted decision process that can drive expensive tank reconstruction expenditures for temporal changes in emissions. EPA's proposed Emissions Guidelines would not require vapor capture from an existing tank if its methane emissions are less than 20 tons/year. EPA's E&P Tanks documentation shows that there are circumstances where a condensate or crude oil tank with less than 20 tons/year of methane emissions could have VOC emissions exceeding 6 tons/year. EPA's revision to the definition of modification provides that the addition of production from any well new to a tank battery will be considered a modification because it alters the tank battery emissions even though the emissions may be well below the design capacity of the tank battery and even though the change may be temporal when the new well's production declines. However, even though the emissions increase might not cause the tank to exceed 20 tons/year of methane, if the tank was already emitting more than 6 tons/year of VOC, vapor capture would be required even though emissions could fall below 6 tons/year of VOC when the production decline. Additionally in an operator had such a battery already controlled under a State permit that doesn't meet the legally and practically enforceable requirements, it would become a OOOOb tank battery. This would require 95% control, when the battery has already likely been controlled well over 95%. So OOOOb is not requiring or resulting in any additional reduction in emissions and actual environmental benefit - just additional regulatory burden. It is anticipated that EPA would not increase regulatory burden without some environmental benefit and the aforementioned scenairo was simply not forseen. It is these presumed unintentional negative consequenes EPA must guard against as they layer regulatory tier upon regulatory tier, with different effective dates.

These cyclical emissions circumstances can drive capital costs for low production operations that result from minor increases in emissions (or no overall emissions increase if an existing well is being transferred from one tank battery to another). It can also create the perverse effect of keeping uncontrolled tank batteries in operation because the cost of retrofitting vapor capture on the "modified" tank battery is too costly. Because EPA overstates the number of existing tanks and tank batteries in its estimates, it believes this modification definition will result in more controlled tank batteries but there is no reason for this expectation. EPA should recognize that there are intermediate control strategies that can provide cost effective emissions reductions, particularly for the universe of low production wells.

In this instance, for example, EPA should provide that where a tank battery is modified because a well is newly added to it but where all of the wells feeding it are low production wells, a cost effective action would be to require an AVO inspection of these tanks to assure that thief hatches are closed and seals maintained until the tank battery emissions exceed 20 tons/year of methane. Such an approach would be consistent with EPA's determination that tank battery emissions of 20 tons/year of methane is the cost effectiveness threshold for vapor capture while achieving emissions reductions from thief hatches and seals that have been identified as a significant component of tank emissions.

13. Producer Associations Support the Concept of Allowing Alternative Measurement Technologies.

Producer Associations support EPA's exploring allowing alternative measurement technologies to being limited or forced to use OGI for every survey - but is concerned that EPA appears prepared to propose overly proscriptive requirements to reduce the flexibility they are intended to provide and greatly diminish their value to the industry. Many of the Producer Associations have argued in the past that EPA should not stifle innovative technologies by selecting one and only one. EPA seems open that concept now, but still heavily dependent as an alternative measurement technology would need to be "validated" by an annual OGI survey. The continued reliance/required on OGI should be closely evaluated. In addition to the continued reliance/requirement to utilize OGI, the frequency and sensitivity requirements EPA appears ready to propose appear excessive and greatly diminish, if not provide a disincentive for regulated entities or consultants to explore the use of alternative measurements. Locking a certain number of surveys and requiring one sensitivity reduce flexibility and could unnecessarily limit the number of measurement technologies that could be utilized. Generally speaking, there is an inverse relationship between frequency and sensitivity - the less sensitivity a technology, the more frequently it should be used and visa versa. Producer Associations, borrowing from a concept advocated by Pioneer Natural Resources USA, Inc., recommend EPA develop a matrix that reflects the inverse relationship to allow for the utilization of more technologies and further spur on new technologies.

14. Appendix K is Unworkable.

Appendix K, as currently proposed, would cause many small businesses to close because they cannot meet the financial, time, staffing, data storage or management obligations of the proposed requirements. Many of the proposed requirements demonstrate the EPA has not utilized an OGI camera in the field and/or is completely divorced from the financial implications of the proposed Appendix K requirements. A member of the Producer Associations is a service-disabled veteran who owns a sole proprietor small business which is currently in the process of certifying his company as a "service-disabled, veteran-owned small business" with the Veteran's Administration and his company will not be able to comply/implement the proposed requirements of Appendix K. This sole practitioner currently owns and uses a Flir Model GF320 to conduct OGI surveys on more than 300 facilities annually which equates to more than 300 hours of field work each year. This member purchased his OGI camera in 2011 and received his OGI certification at Flir's headquarters in New Hampshire in 2011. Since 2010, he has completed 1000's of hours of field experience and surveys at 1000's of oil and gas facilities, wells and manufacturing facilities over a 12-year period.

With the massive increase in training requirements and camera use proposed in Section 1.0, it appears EPA only solicited input from OGI camera manufacturers who are interested in increased revenues from selling week-long training seminars at $2000 plus travel expenses, maintenance and repair of equipment and early replacement of $90,000 to $120,000 cameras because of the excessive wear and tear use required for training, documentation and auditing.

Small businesses do not have access to advance laboratories and/or the funding necessary to purchase, construct, operate, or maintain the proposed initial performance verification as required in Section 6.1.2. As EPA has done in the past, EPA should place these requirements on the manufacturers as certifications prior to sale of the equipment and not the end-users.

Did the EPA intend for the Section 8.0 to be specific to camera manufacturers or did the EPA intend for this work to be required by camera operators? The EPA was not clear with respect to whom is required to complete this work. Many small businesses do not have the space or access to equipment and facilities the required testing protocols required in Section 8.0. This would create an excessive financial burden on small businesses and likely preclude small businesses from competition with larger entities. Further, our sole proprietorship and single entity small business member indicated the current local availability of other certified OGI camera operators to be limited. Their discussion with state employed and certified OGI operators indicated limited state interest in working together to meet Appendix K performance verification and on-going annual auditing because of a "conflict of interest." What is the EPA proposing to allow an equal playing field for small businesses with regard to Section 8.0.

Facilities have hundreds, if not thousands of components. Section 9.4 of the proposed regulations proposed a 5-second dwell time per component and runs counterintuitive to the EPA's original advocation for the OGI camera to be used as an approved Alternative to Method 21. The EPA originally touted the OGI camera as an efficient methodology to quickly scan and survey thousands of facility components. Despite the high initial capital cost, many companies saw this as a cost-efficient methodology to rapidly scan, find, document and communicate necessary leak repair. The EPA's proposed Appendix K protocols, primarily the 5 second dwell time dramatically lessen the efficiency of the camera and the cost of utilizing the camera provides little to no economic benefit over the traditional Method 21 LDAR.

A 5-minute break for every 20 minutes of work as stated in Section 9.5 is unjustified, if not insulting to small businesses and individuals that purchased the camera, were trained and certified to operate and have thousands of hours of field experience. Is the EPA suggesting that senior level camera operators are not capable of defining specific rest intervals based on experience, training, physical conditioning, etc.? Is the EPA suggesting that all camera operators have similar operating limitations? Is the EPA proposing to provide scientific and medically backed studies to support their conclusions and substantiate the proposed requirements in Section 9.5 of Appendix K? The EPA should allow individuals and small businesses the freedom to determine operational approach and site-specific need for intermittent breaks.

How is the EPA proposing to level the playing field for sole proprietorship companies that cannot meet the proposed requirement of having 2 camera operators, as proposed in Section 9.5 when engaged in continuous monitoring? This requirement is highly discriminatory and would likely prohibit senior level certified small business camera operators from conducting large facility inspections.

The EPA does not define what constitutes a "break." Senior level certified OGI operators suggest that 20 minutes of continuously looking through the camera would be excessively long and dangerous. On most occasions, OGI camera operators survey for leaks at 1-3 minutes intervals from a fixed location prior to moving to another fixed location to scan the same components from a second angle. During these movements between fixed locations, senior level certified OGI camera operators cease to look through the camera. Are these movements when not looking through the camera considered a "break" by the EPA? Senior level certified OGI operators remarked on how dangerous movement around complex facilities would be while looking through the camera because the camera viewing window is optically skewed and has limited peripherally capability.

The EPA proposed ambient weather documentation in Section 9.6.2 and should clarify time intervals of ambient weather documentation. Increases in monitoring requirements proposed in 40 CFR Part 60, Subpart OOOO(a), Subpart OOOO(b), Subpart OOOO(c) and Subpart OOOO(d) effecting small marginal wells with minimal emissions would make collecting ambient weather on intervals of less than 15 minutes impractical and time consuming. For example, an OGI survey of a small central tank battery and well facility may only take 15 mins to survey all components vs.

possibly 8 to 10 hours for a larger natural gas processing facility. Would OGI camera operators be required to document weather changes every 7.5 minutes as proposed in Appendix K?

As proposed in Section 9.7.1, the required documentation time of a minimum of 10 seconds per leak defies the original intention for performing OGI surveys. The EPA originally supported OGI inspections as a quick and efficient Alternative Method 21 technique allowing companies to survey 1000's of components quickly and allow efficient communication to staff for repair. A 10-sec video for each leak would be impossible to quickly communicate necessary repairs because of file size and video quality. The video quality in all camera operating modes is very low quality and not useful or efficient for maintenance staff to make repairs. This low-quality video would make an accessory, high-quality digital photograph also necessary to document and communicate a leak. Why would the EPA want to require the capture of a minimum 10-second per leak video if the low-quality videos are not useful to maintenance staff? This requirement is wasteful of time and resources and offers no benefit to efficient leak surveys.

One senior level certified OGI operator and service-disable veteran small business owner member suggested that survey techniques should have the flexibility to meet the needs of the producer and should allow for modifications for business size and staff, communication ability (in remote areas), availability of on-site maintenance staff and fluctuations in daily operational agendas. While operators should be afforded flexibility on how to calibrate their equipment, identify a leak and communicate that to maintenance, one member recommended the following survey approach, data capture and communication methodology.

a. Conduct beginning-of-day field calibration verification using the EPA approved Eastern Research Group, Inc.'s "Disposable Lighter Mass Emissions Study" to confirm the OGI camera's operational capability.

b. Identify the leak using the High Sensitivity Mode (HSM) with the correct temperature alignment to control ambient background temperature interference.

c. Flag the leak with survey ribbon and write the date of detection on the ribbon. Mark the exact component leak location with a hardened wax crayon. Hardened wax crayons work well on all types of materials including painted metals, bare metals, plastics, rubber, etc. and also work in all types of ambient weather conditions, *i.e.*, cold, hot, wet, snow, etc. The use of the wax crayon allows the OGI camera operators to highlight the exact location on a valve, flange, tank, connection, etc. for later identification by maintenance and repair personnel.

d. Take a digital photograph with the OGI camera of the leak to capture the date, time, and GPS location.

e. Document the leak in a field book and include all specifics including component type, location of the leak and anything else pertinent to maintenance staff for repair of the leak.

f. Take a photograph with phone camera and send a text message to the operations or maintenance manager with notes from the field book at the end of each facility survey or at the end of each survey day. This allows the operations or maintenance manager to easily forward the text message with the photograph and description and location of the leak to appropriate maintenance staff. Text messages are preferred rather than email because of the remote nature of many oil and gas facilities. Text messages will go through where internet and phone service is not always available. Also, travel between sites and from an office can be long preventing finalization of the OGI survey reports with photographs, location and leak types for several days. This process gets the information into the hands of those who make repairs quickly and efficiently.

g. When maintenance staff have completed the leak repairs, they text message the OGI operator directly with the specific information to allow documentation on the final OGI summary report.

h. If a facility or well is not observed to have leaks, a high-quality photograph is taken with the OGI camera to capture the date, time and GPS location to validate the survey was completed.

i. Conduct end-of-day field calibration verification using the EPA approved Eastern Research Group, Inc.'s "Disposable Lighter Mass Emissions Study" to confirm the OGI camera's operational capability.

j. Upon return to the office, all leaks and location have been communicated to operators and repair attempts or completed repairs have been communicated back to the operator. At this point, a report is created detailing the summary of work, calibration documentation and individual facility documentation pages that capture location, weather conditions, found leaks, repair dates, etc.

Our senior level certified OGI camera operator members also commented on the costly and problematic requirement of a 10-second video capture for each leak recording by citing the massive amounts of storage space considering the 5-year recordkeeping requirements, stating that OGI camera videos can easily be corrupted and that high-quality digital images are smaller files and easier to communicate via commonly accepted methods.

Senior level certified OGI camera operator members commented that the requirements of Section 9.7.3 would substantially reduce the life of the camera and require unnecessary and costly maintenance and replacement. Section 9.7.3 would also require massive amounts of data storage over the 5-years of recordkeeping requirements. Further, the necessary documentation of procedures the operators uses will change based on individual specific site requirements. The EPA provides no guidance on minimums and/or how the requirements would be met. The EPA commissioned the Eastern Research Group, Inc. a couple of years ago to develop a quick calibration field protocol meant to allow quick calibration and verification of the camera. The resulting "Disposable Lighter Mass Emissions Study" was approved by the EPA for use and required the calibration and verification technique be conducted at the beginning and end of each survey day. The technique involved a 13 to 19 second video using a butane lighter to capture a video using each camera setting. This technique is efficient and effective. Our senior level certified OGI operator members have indicated that EPA field staff stated this methodology was created because EPA inspectors often fly to various areas and couldn't find the necessary equipment to conduct the original calibration and verification requirements. Allowing this technique to continue would allow EPA inspectors and private OGI camera operators to fly, rental car, stop at any gas station, buy a lighter, and easily conduct a calibration and verification in the field. The proposed regulations in Appendix K will create a similar situation which would complicate both the EPA's field staff ability to meet their own rules and prohibit private OGI camera operators from completing the EPA required monitoring for oil and gas facilities.

In Section 10.1, the EPA doesn't provide clarification on the specific training requirements. How would a sole proprietor small business complete this training? Currently, no refresher training is available that would facilitate senior level certified OGI operators. Is the EPA suggesting that senior level certified OGI camera operators must retake basic OGI certification training annually? The EPA should consider providing short, efficient training seminars to allow experience senior level OGI operators to obtain refresher tips, techniques, etc. similar to the required 8-hour HAZWOPER training. Online training is not currently available for refresher training and significant time, travel and course costs for in-class training would provide an economic burden for small businesses and sole proprietorships to complete. The EPA should consider providing alternatives for small businesses and specify explicit exemptions for senior level OGI camera operators with a certain level of field experience.

How is the EPA proposing to provide an equal and level playing field for senior level certified sole proprietor and small business OGI camera operators to complete the requirements in Sections 10.2.2.1 through 10.2.2.4? Are senior level certified operators required to complete these tasks? If the EPA intends to add more OGI operators to meet demand, these regulations would severely limit small businesses from adding OGI operators and services.

In section 10.2.2.4, the EPA is requiring two cameras to complete the final site surveys. At roughly $90,000 – $120,000 per camera, what is the EPA proposing to allow an equal and level playing field for small businesses and sole proprietors to complete these final site surveys? Small businesses and sole proprietors cannot financially meet this requirement and have commented on the inability to find other senior level certified OGI staff willing to cooperate with competing small businesses and sole proprietors to achieve the EPA's proposed requirements.

In Section 10.3, the EPA is requiring in-class training to meet the annual refresher training. This appears exceptionally tone-deaf in the era of COVID-19 lockdowns, travel restrictions, medical exemptions, etc. Further, senior level certified OGI operator members have stated that classroom training typically lasts 3-days and is only offered in major cities. This would require an enormous amount of resources for small and sole proprietor businesses, while also restricting their ability to earn revenue during excessive travel for annual classroom training. These requirement in Section 10.3 combined with all other requirements in Appendix K would substantially reduce small businesses and sole proprietor's ability to provide services and earn revenue. Senior level certified OGI operator members have asked if the EPA's goals for Appendix K was to require OGI operators to fulfill training and auditing standards or to provide quality, site-level field survey to reduce methane emissions. Senior level certified OGI camera operator members have indicated a willingness to participate in 8-hour online training seminars presenting new tips, tricks, techniques and discussion, but indicated that spending a week sitting in a classroom listening to an instructor with less field experience explain the fundamentals would be a significant was of time and resources.

In Sections 10.4 and 10.4.3, how is the EPA proposing to assist or provide a sole proprietor small businesses a level and equal playing field to meet these standards? Who is going to quarterly evaluate a sole proprietor as the senior OGI camera operator? Are senior OGI camera operators exempt from the regulations? The EPA needs to explicitly define a senior level operator and include qualifications and exemptions. Senior level certified OGI camera operator members have also commented on the excessive requirements of 4 hours of survey data resulting in a shortened camera life span, more frequent repair costs and require a massive amount a data storage space when aggregated with other requirement of Appendix K.

Regarding the Quality Assurance and Quality Control proposed in Section 11.0, senior level certified OGI camera operator members have commented on how the EPA proposes to provide an equal and level playing field to allow small businesses and sole proprietorships with limited resources and staff the ability to complete these proposed objectives? Senior level certified OGI camera operator members have mention that the proposed requirements contradict the original intended use of the camera and would add significant cost and time. Who did the EPA solicit comments and input from before designing the proposed requirements? Did the EPA solicit comments and advice from small businesses and sole proprietorships prior to publishing Appendix K or did the EPA speak only with camera manufacturers who want to maximize camera use in order to expedite the failure rate to drive up maintenance and new sales revenue?

In addition to the above comments, primarily from the perspective of a small business owner, the Producer Associations generally support and incorporate by reference the comments of the American Institute on Appendix K and attached as Exhibit A.[15]

15. EPA Continues to Not Understand Liquids Unloading.

The EPA should focus only on liquid unloading events resulting in venting and not the "design" of the liquid unloading method. The "design" of the methods, venting or non-venting, is NOT relevant. The EPA co-proposed options to use "the wells' designed unloading methods and whether the methods are designed to vent or not as the determination basis for an affected facility" would create significant ambiguity. The design of a well's liquid unloading strategy often has multiple possible outcomes depending on various factors that can change daily, *e.g.*, operating temperatures and pressures, reservoir behavior, gathering and compression systems, offset well affects, availability of equipment and personnel, and the actual daily history of unloading attempts. Any attempts to define affected facilities based on whether a well is designed to vent during unloading or not would be problematic as both design possibilities may exist concurrently. The current GHGRP rule determination, *i.e.*, gas wells that vent should be maintenance as the basis for an affected facility.

[15] If API agrees Paragraph 9.7.3 should be deleted, then Producer Associations believe the requirement for videoing leaks should also be deleted. Additionally, Producer Associations suggest that Section 13.B be revised to make clear that the refresher level of training of OGI certified thermographers would not be required in the initial year of applicability for Appendix K.

All wells will eventually require liquid unloading and the methods to unload liquids throughout the life of the well will necessarily change depending on the conditions of the well. As the well matures, a method that is successful in routing the well stream to a separator with no venting, may eventually cease to unload liquids due to changes in well conditions. For example, a well is equipped with a plunger system to route the well stream to a separator and subsequently, sending gas to the sales line with no venting. Changes in well conditions leading to insufficient pressure differential to unload liquid would require unloading to an atmospheric storage tank with minimal venting. In this scenario, the EPA should only require reporting of the events that result in venting and omit any references to the non-venting "design" of the liquid unloading method as it is not relevant in terms of the intent of the rule, *i.e.*, minimizing vented emissions and the inherent ever-changing conditions of the wells.

In terms of recordkeeping, the EPA must consider existing data as reported under Subpart W to account for liquid unloading events resulting in vented emissions. It is NOT warranted to maintain records for non-venting events. Additionally, the lack of a framework for what constitute a non-venting event renders it impractical or not possible to qualify or quantify a non-venting event. For example, the time period when a well equipped with a plunger system which sends the well stream directly to a separator with no vented emissions would qualify as a non-venting period. How would liquid unloading events during this period be quantified? A count of plunger cycles that successfully lift liquids and unload? From this perspective, the EPA should omit any considerations in regard to record keeping and reporting requirements for non-venting liquid unloading events.

a. For reporting of liquid unloading events that result in vented emissions, the EPA currently requires reporting of liquid unloading vented emissions under GHGRP 40 CFR Part 98 Subpart W using Equations W-7, W-8, or W-9 of §98.233(f). Producer Associations urge the EPA to consider existing data reported under this Subpart and not impart additional unnecessary reporting requirements.

b. Almost all wells unload liquids, therefore the unloading event itself should not trigger a modification.

   Almost all wells experience liquid unloading during the natural production of the well, many without any equipment modification and as a stage of "primary" production. Even gas wells that do not contain any movable liquids in the formation will generate liquids due to condensation of the liquid vapor in the gas as the gas cools during production from the downhole formation to the surface wellhead. With time this liquid can accumulate in the wellbore and can temporarily load the well until the well pressure increases naturally under this fluid column until there is sufficient pressure/ energy to unload the liquid column. Unloading is not necessarily a physical or operational change and does not result in the potential for increased emissions when wells do not vent as previously mentioned. Therefore, they should not be considered a modification.

c. Option One would apply to almost all wells, and therefore should be eliminated. Since almost all wells experience liquid unloading. The application of Option One would therefore apply to almost all wells, even wells that are still producing naturally without any added artificial lift technology. This would be an unreasonable record keeping request and therefore Option One should be eliminated from the proposed rule.

d. Producer Associations support Option Two for gas wells that actually vent only. Reporting for wells that do not vent is burdensome, with no emission benefit, and too broad in scope.

e. Producer Associations support Option Two as follows: Affected facility would be defined as every well that undergoes liquids unloading using a method that vents. Wells that utilize non venting methods would not be affected facilities that are subject to the NSPS OOOOb. Therefore, they would not have requirements.

f. Producer Associations support the use of BMPs when venting is required for liquid unloading. As proposed "for unloading technologies or techniques that result in venting to the atmosphere, implement BMPs to ensure that venting is minimized. Maintain BMPs as records, and record instances when they were not followed."

g. Producer Associations support liquid unloading BMPs that empower production engineers to direct unloading activities without technical justification and that are aimed at daily operational venting minimization.

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

Producer Associations agree per 86 FR 63180: However, 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 for such cases (discussed in section XII.D of this preamble).

Producer Associations agree per 86 FR 63213 "The EPA recognizes that there may be safety and technical reasons why venting to the atmosphere is necessary to unload liquids. In addition, it is possible that a well production engineer has already explored non-venting options and determined that there was no feasible option due to its specific characteristics and conditions."

Producer Associations agree per 86 FR 63211 "Selecting a particular method to meet a particular well's unloading needs must be based on a production engineering decision that is designed to remove the barriers to production."

Based on the following three statements it should be evident that if there was a solution that did not require venting it would have been selected by the Production Engineer.

h. Producer Associations support BMPs that:

i. Require the reporting of vented emissions as per "Gas Well Venting for Liquids Unloading according to Petroleum and Natural Gas Systems source category of the GHGRP 40 CFR Part 98 Subpart W using Equations W-7, W-8, or W-9 of §98.233(f)"

ii. That require an operator at the well site or in close proximity unless the use of automation equipment, remote sensors, and other surveillance technologies are used.

iii. That require the operator to report when the BMPs have not been followed.

iv. Allow for the use of flaring as a control option.

v. Allow for routing emission to a sales line or back to a control process.

vi. For States where a BMP governing liquid unloading event is required under the States' NSR program, such BMPs should be deemed sufficient and satisfy the requirements of NSPS.

Although many member companies employ the Best Practice Implementation Principle as outlined defined in the API's The Environmental Partnership Program for Manual Liquids Unloading: Operators commit to monitoring the manual unloading process and close all wellhead vents to atmosphere it is important to point out that the definition of Manual Liquids Unloading is: an operation undertaken by an operator to temporarily divert the flow from the well to an atmospheric vent without assistance of automated equipment, and the definition of Monitored: operator on-site or in close proximity and able to close atmospheric vent as soon as practicable to minimize the gas vented to atmosphere. The use of automation is a very important point in this BMP formulation. The use of remote sensors, mechanically activated devices, positive closure and seal indicators, camera technology, and associated surveillance and alarming can greatly enhance the effectiveness of optimal liquid unloading and in many cases is more effective than relying on personnel to be on site. Therefore, any BMP should not require having a person onsite during the liquids unloading event to expeditiously end the venting when the liquids have been removed as suggested on pg 63179. Rather BMPs should encourage the continued use and expansion of use of automation technologies that are very scalable and economic.

Automation also reduces the safety risk of exposing personnel to hazardous atmospheres.

EPA states that based on the [16] U.S. Environmental Protection Agency. Oil and Natural Gas Sector Liquids Unloading Processes. Report and peer reviews on the technical and cost feasibility of using a flare to control vented emissions from liquids unloading events indicating that a flare cannot be used in all situations, we did not consider this option any further in this proposal. One cited peer review [17] stated "The flowing characteristics during venting operations inhibit the design of flare equipment. During the unloading operation, initial gas flow rate and pressure are high and decline rapidly over a short time period. Flare design (tip diameter) is based on flow rate and design criteria can be found in Radian Corporation / EPA 1995 Report – Chapter 7 on Flares[18]. In addition, the sporadic nature of liquid unloading venting operations would require either a continuous pilot or electronic igniter. The design cost associated with the requirements needed for this type of flow would be cost prohibitive." Additional information for flare applicability in this context is available in EPA Gas Star PRO Fact Sheets No. 904 "Install Flares" and No. 903 "Install Electronic Flare Ignition Devices".

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

Production Engineers will always attempt to capture methane emissions and put them into the sales line when practical. During plunger lift, gas lift assist, soap assist, venturi system lift, swabbing, and many other forms of liquid unloading gas is often captured and routed to sales or to a control device, *e.g.*, flare, compression input, heaters, generators, etc. "Selecting a particular method to meet a particular well's unloading needs must be based on a production engineering decision that is designed to remove the barriers to production." In many cases there are way to achieve this with going to sales or a control device, but when they no longer can do so they still require the ability to vent. There are many Gas Star PROs that address the cost side of these solutions that are highly variable.

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[16] U.S. Environmental Protection Agency. Oil and Natural Gas Sector Liquids Unloading Processes. Report for Crude Oil and Natural Gas Sector. Liquids Unloading Processes Review Panel. April 2014.

[17] Jim Bolander, P.E., Senior Vice President, Southwestern Energy (SWN). Review Submitted: April 2014. Pg. 8

[18] Chapter 7 FLARES: Diana K. Stone, Susan K. Lynch, Richard F. Pandullo, Radian Corporation Research Triangle Park, NC 27709, Office of Air Quality Planning and Standards U.S. Environmental Protection Agency, Research Triangle Park, NC 27711, December 1995

In various state approved BMPs (NM, PA, CO), there are common elements which are non-prescriptive and allows for operators' expertise in the selection of appropriate liquid unloading practices. The commonality or consistencies of these elements reflects recognized and common practices that are proven; It is recommended that the EPA considers the application of these common elements in determining the minimum elements requirements. One such common practice is to require monitoring during a LU event via the presence of an operator on-site or in close proximity. The application of remote monitoring via sensor technology may also be employed as feasible.

Producer Associations also urge that for States where a BMP governing LU event is required under the States' NSR program, such BMPs should be deemed sufficient and satisfy the requirements of NSPS.

i. Producer Associations object to BMPs with any of the following requirements as they would be a record keeping and reporting burden with no direct emission reduction benefit:

    i. Technical justification for the unloading methodologies employed.

    ii. Process flow explanation and or diagrams of unloading activities.

    iii. Historical account of all activities associated with attempts to unload wells.

Producer Associations agree with 86 FR. 63211 "Selecting a particular method to meet a particular well's unloading needs must be based on a production engineering decision that is designed to remove the barriers to production."

Describing clearly where a well stream is directed via a process flow diagram and explanation is not in most cases a trivial explanation. Many well sites, especially sites with multiple wells, have a complex surface piping system for equipping the site with the various liquid unloading activities that could result, *e.g.*, gas injection, recirculation of produced gas in well site compression, VRU control options, combustors, oxidizers, multiple use of separators and tanks often manifolded together, soap and chemical delivery systems, and so on. The current reporting methodology options in calculating annual natural gas emissions from Gas Well Venting for Liquids Unloading according to Petroleum and Natural Gas Systems source category of the GHGRP 40 CFR Part 98 Subpart W using Equations W-7, W-8, or W-9 of §98.233(f) are adequate.

j. Producer Associations object to BMPs with any of the following requirements as they would be a safety concern:

    i. Requirement for the direct measurement of vented emissions.

    ii. That require an operator in close proximity to the unloading activities when the use of automation equipment, remote sensors, and other surveillance technologies are used.

An emission quantification hierarchy of direct measurement, engineering equations, and emission factors will for almost all sources result in the most accurate emission values. However, engineering challenges, economic criteria, and safety considerations will result in the optimal selection on a case-by-case basis.

There are safety concerns regarding direct measurement of venting emissions. [19]NIOSH-OSHA have issued a Hazard Alert associated with working around open top tanks. This Hazard Alert describes the safety and health hazards when workers manually gauge or sample fluids from production, flowback, or other tanks. It recommends ways to protect workers by eliminating or reducing exposures to hazardous atmospheres, and actions employers should take to ensure that workers are properly aware of the hazards and protected from exposure to hydrocarbon gases and vapors. This alert is a supplement to the [20]OSHA Alliance Tank Hazard Alert released in 2015 [National STEPS Network 2015]. Although there are many cases of direct measurement being performed on methane emissions many of them are done in a controlled experimental environment. In reality workers should use extreme caution whenever working around hydrocarbon emissions and many of the direct measurement techniques used and suggested, *e.g.*, see [21]CCAC Appendix A; turbine meters, vane anemometers, hotwire anemometers, actually expose workers to these emissions and therefore should be avoided.

See also supporting information remarks under item 9 regarding the use of automation equipment.

k. Producer Associations object to BMPs with any of the following requirements as they would be too prescriptive in nature and would potentially impact the Production Engineer's best design decisions:

   i. Any prescriptive requirement for using any specific unloading technology, like the requirement to try a plunger lift, or attempt the use of an artificial lift engine, both of which can be found in the New Mexico draft language.

l. The following are examples of technical obstacles that would not allow liquids unloading to be performed without venting:

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

[20] OSHA Alliance Tank Hazard Alert released in 2015 [National STEPS Network 2015]. https://www.cdc.gov/niosh/docs/video/2017-158d/default.html

[21] CCAC Appendix A: Conducting Emission Surveys, Including Emission Detection, and quantification equipment.

i. Production Engineers should be empowered to make the best production decision, and when they decide venting is required, it should be considered technically necessary.

ii. Many wells need to unload to an atmospheric tank for unloading to be successful.

iii. Sporadic unloading is difficult to model and the selection of surface equipment that does not vent creates safety concerns.

iv. Separation equipment requires threshold operating pressures and perform poorly under sporadic flow.

v. The use of compressed nitrogen to unload wells often requires some venting.

vi. High surface producing pressures can result from gathering and compressor system maintenance or unplanned upsets. Wells often cannot unload against these higher surface pressures.

vii. Locations are often too small to accommodate the significant amount of equipment which would be necessary for non-venting liquids unloading.

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

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

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

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

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

Regarding cost, given enough money a non-venting solution may be possible in almost all cases but the amount of equipment, additional artificial lift engines and associated secondary emissions often makes this an obvious poor choice. Location size can also prevent the installation of any such equipment, particularly when adequate and prudent spacing between wellheads and other potential ignition sources and fired equipment such as compressor exhaust and flares. Production Engineers are professional problem solvers, and they should be empowered to come up with the best solutions as alluded to in the preceding comments.

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

m. The routing of emissions back to a sales line is possible but not always practical and does create secondary emissions:

One operator uses mobile gas lift compressors (MGLC) to unload wells to minimize venting emissions. Estimated cost for routing unloading emissions to the sales line using mobile gas lift well site compressors for one operator cost $280,000/year. The equipment size, layout, spacing requirements (Fire Class/Divisions), and cost would make it difficult to justify for use on marginal or remote wells. The secondary emissions from the 3406 gas powered compressor are approximately 4 tons/event CO_2e.

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

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

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

Velocity string sizing requirements change with time requiring replacement. They are therefore not considered permanent solutions for liquid unloading. The increased emissions, and cost was not considered in the BSER analysis.

o. Cost effectiveness analysis: The CAA section 111(a) requires that the EPA promulgates standard that "has been adequately demonstrated." based on technical feasibility and cost effectiveness. Producer Associations question the EPA on the methodology which was employed to establish cost reasonableness.

  i. The EPA is to establish $/tons of emission reduction in establishing reasonableness yet there is no data on emission reductions from the study. The EPA acknowledged that establishing an emission reduction that would be achievable by event is difficult as baseline level of management practices and emissions varies significantly. Therefore, the EPA calculated the $/ton reduction from the baseline level based on hypothetical values of 10%, 25%, and 50%. As stated, these are hypothetical values and therefore, questionable as representing reduction per event. Additionally, the baseline emission is a crucial factor in calculating the tonnage of reduction; yet, the EPA lacks transparency in providing justification for the baseline emissions applied in the calculation of cost effectiveness. As such, we question the EPA on the cost effectiveness of the "Non-Emitting Evaluation" option.

  ii. To establish the cost effectiveness for existing sources, that is, wells already equipped with "non-venting" technology such as plunger lift, the EPA's analysis is based on 2015 – 2019 LU data from the GHGGRP. The data shows 98% of "with plunger" wells are those equipped with automated plunger for which the EPA cannot establish an emission reduction baseline. Hence, the analysis is based on the remaining 2% of the well population representing manual LU operation. We question the representation of this analysis as 98% of actual wells are equipped with automated plunger system based on which the EPA cannot establish actual reduction.

16. EPA Fails to Appreciate the Variety of Reciprocating Compressors Utilized by Different Segments and Plays Across the Country.

The Producer Associations recommend that EPA not revise the current regulations under Subpart OOOOa. In the alternative, instead of considering the annual review based on a calendar year (*i.e.*, 365 days) the Producer Associations recommend that EPA consider with respect to operation of annual number of hours (*i.e.*, operation of 8,760 hours). First, it may be difficult for operators to measure the leak rate to determine if the rate has exceeded the 2 scfm and operators may have to default to replacing the packing annually in order to comply with this requirement. As EPA's intent is to have a reasonable amount of time pass before review, it should be based on actual use instead of potential use. Operator experience with the booster and gathering compressors suggest that the rod packing is necessary every four to five years. Other compressors are used to kick off a well after a workover run far less than 8760 hours a year like certain midstream compressors. As there may be situations where the reciprocating compressors are not used, this would make sure operators are not having the burden of going through the reviews even if the compressor has not been operating for multiple months.

EPA states it will apply this proposed monitoring requirement for reciprocating compressors located at "centralized production facilities." This may be beneficial in certain operations and where larger oil and gas operators may have the resources and equipment to monitor those emissions; however, it should be an option/alternative, and not a mandatory requirement as it may unnecessarily create additional burdens and costs for smaller operators that send production from several marginal/low production wells to a "centralized production facility." For marginal/low production well operators, centralized production facilities may be more cost efficient than having equipment at each well site and this practice reduces overall the environmental footprint of the operation. This would be an unnecessary additional cost on small businesses and disincentivizes the use of centralized production facilities in this scenario. The Producer Associations request EPA remove this requirement for marginal/low production wells that send production to centralized production facilities.

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

While it may be cost-effective to regulate larger compressors, it would not be for smaller units. The benefits that could potentially come from requiring replacement for these smaller units is outweighed by the significant cost. The cost is estimated to be between $2,500 to $7,500. Not all units will need it though especially if the packing vents are taken to a closed loop system.

It is very clear that the EPA is either unaware of or does not understand the impact that the proposed OOOOb regulations will have on the large number and variety of existing gathering and boosting compressor stations in gas fields across the country, especially in the Appalachian Basin. In the Appalachian Basin, most of the compressor stations are operated by small locally-owned companies that meet the definition of a Small Business Entity. Under the 2016 OOOOa regulations, existing compressor stations were exempt from fugitive emission surveys, but OOOOb now proposes to regulate all compressor stations; even small wellhead compressors that were previously exempt. OOOOb will require small operators to implement expensive fugitive emission surveys and recordkeeping, resulting in little or no reduction of methane emissions.

Most of the low volume and low-pressure wells in the Appalachian Basin are connected to a compressor in order to get their produced gas to a market. Most of these wells consist of just a wellhead which the EPA rightly has proposed to exempt from OOOOb or OOOOc regulation. The compressors used by the small companies are most commonly of two types, booster compressors, and field compressors. The booster compressors are typically small single stage units with low horsepower drivers connected to a well or groups of low-pressure wells that would not be able to deliver gas into a gathering system without help. A typical situation gathers small volumes of gas at very low pressures from groups of legacy oil wells found in many areas of the Appalachian Basin. These wellhead compressors, which were exempt under the 2016 OOOOa regulations, typically move around 10 Mcf/d with a suction pressure as low as 0 psi and discharge pressures of between 8 and 20 psi. Because of the pressures at which these compressors operate, they have a very small potential for fugitive emissions and should continue to be exempt from OOOOb regulation.

Booster Compressor

The operating parameters and designs of compressor stations are dependent on the volume and pressure of gas available from the wells it serves, the pressure of the pipeline the gas is being delivered into, and the water content of the gas moving through it. The larger field compressor stations, which can deliver several hundred Mcf per day into gas gathering systems or transmission pipelines usually include compressors with natural gas fueled engines with higher horse power ratings and include glycol dehydration equipment. But by far the most prevalent compressor stations operated by the small companies in the Appalachian Basin include compressors that move between 100 and 200 Mcf/day and driven by either electric motors or natural gas fueled engines of 150 horsepower or less. The majority of these size compressor stations only have compressors and their drivers, but glycol or desiccant dehydrators may be required in cases where water content of the gas is high.

Compressor Station with Desiccant Dehydrator

The typical Appalachian Basin small field compressor stations are not large facilities. They cannot be compared to the large high volume and pressure compressor stations and gas processing plants associated with deep unconventional shale gas production. A compressor and driver only station operated by small Appalachian Basin companies, do not have much more plumbing than a typical Appalachian Basin wellhead. The suction side plumbing will be operated at the low suction pressures of the compressor and only a very short distance of discharge plumbing is operated at discharge pressures typically less than 300 psi. As with wellheads, thread leaks or vented gas associated with the brief blowing of a drip tank at a compressor station, are not significant emission sources. The leaks can usually be identified using soap bubbles, and they can easily be corrected with a pipe wrench at the time of inspection. Even though small company compressor stations are not manned 24 hours a day, they are visited weekly, if not daily. Audio, visual, and olfactory (AVO) surveys during these frequent visits are far more cost effective for the small companies than quarterly optical gas imaging (OGI) surveys. Leaks don't go unnoticed for any length of time.

EPA's estimated 16 tons per year emissions from these small compressor stations is a dramatic over statement of methane emissions. DOE methane emissions study about to be published by GSI found average methane emissions at the compressors they surveyed in the Eastern US of 1.3 kg/day, or less than a half ton per year. Because of the low suction and discharge pressures at which they are operated, compressors and compressor station equipment typical of small company operations are not large fugitive emission emitters.

The fugitive emission surveys of compressor stations using OGI as will be required under OOOOb, is a service not readily available in many areas of the country; this resource constraint will only further be exaggerated by the proposed requirements from Appendix K. The costs to bring in the equipment necessary from other areas of the country four times a year are prohibitive. The EPA estimates that cost to be $13,400 per year per compressor station. For compressor stations that deliver 100 Mcf per day, that is an additional cost of $0.372 per Mcf or 11.9% of a gross price for gas of estimated by EPA to be $3.13 before any operating costs. A significant cost to the small companies making some gas fields uneconomical to continue to produce. Booster compressors gathering associated gas from oil wells would disappear completely.

Additionally, the current requirement of replacing rod packing of a reciprocating compressor every 36 months is also a burden to the small operator. Unnecessary maintenance and down time hurts revenue with no material benefit. Rod packing in compressors that run at relatively low pressures and RPM can last well over 60 months. Even longer is the compressor runs intermittently.

Producer Associations make the following recommendations to the EPA:

a. The compressor stations, which include wellhead boosters that were exempt under OOOOa, and compressors and drivers and other equipment such as dehydrators, with throughput less than 55 MMcf per year (average 150 Mcf per day) be exempt from OOOOb regulation, specifically fugitive emission surveys and recordkeeping requirements.

b. Allow the option for OGI surveys to monitor rod packing leaks. If a leak is found during an annual survey, then use measurement to determine a rate and need for replacement. Well pads should be exempt from rod packing replacements for many compressors are not used 8760 hours per year and the amount of money spent may not be cost effective in reducing emissions. Utilize run hours as a metric versus annually monitoring for rod packing replacements on well pads.

17. Revisions to Well Completions Must Retain Certain Exceptions.

Producer Associations appreciate EPA's review of standards for well completions and their understanding of completions involving conventional wells in low pressure and low permeability reservoirs as typically found in the Appalachian Basin. These low pressure and low permeability wells require stimulation to produce hydrocarbons at economic rates, but often can be produced economically for many decades. Because of the low pressures, the stimulations often include energized fluids, were an inert gas, such as nitrogen, is added to help bring the fluids out of the formation. In many cases, the stimulation is performed with just the inert gas. The inert gas makes green completions impossible and the typical duration of flow back very short, typically less than 48 hours. The challenge is that the flowback will not combust due to the high nitrogen content.

EPA's continued approval of Reduced Emission Completions that were originally set out in OOOOa, is important for the consistent regulatory structure in the development of the low pressure reservoirs in the Appalachian Basin.

18. EPA Needs to Allow for Several Exemptions for Requirements to Control Associated Gas from Oil Wells.

EPA is proposing a standard under NSPS OOOOb/c that requires owners or operators of oil wells to route associated gas to a sales line. In the event that access to a sales line is not available, EPA proposes that the gas 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. EPA's efforts to restrict venting of associated gas may be appropriate for certain scenarios; however, there may be situations where new wells or existing wells that currently do not have gas sales pipeline line to them are either not available, feasible or economic. In addition, there may not be adequate volumes or quality of gas to use onsite or route to a flare. EPA should allow exemptions for these situations, especially for marginal/low production wells, where lack of adequate volumes or gas quality preclude its use onsite or routing to a flare. In all other situations, EPA should allow options that operators can implement that best fit their operations.

19. Abandon Wells are Best Addressed By Existing State Programs.

First, EPA broadly characterizes abandoned wells as oil or natural gas wells that have been taken out of production, which may include a wide range of non-producing wells such as idle, inactive, dormant, shut-in, and orphaned wells. These wells, except for orphaned wells, typically have a responsible owner/operator but are not producing for a specific reason *e.g.,* product pricing, held by other production in the unit, or waiting on some specific activity like a workover. On the other hand, an orphaned well is a well where there is no responsible owner/operator *e.g.*, the owner/operator has gone bankrupt. EPA should not broadly characterize these wells collectively as they are very different and the existing state programs are addressing this problem with much appreciated federal assistance. For EPA to attempt a federal overlay of the state programs would represent a step backwards.

In November 2021, President Biden signed into law the infrastructure bill that includes $4.7 billion to restore and plug orphaned wells on federal, state, private and tribal lands (aka REGROW Act of 2021). In December, the Department of Interior released guidance on state applications for grants under the program. Since then, many states, including Oklahoma, have applied for this funding and are aggressively prioritizing and addressing the plugging of orphaned wells. The Interstate Oil and Gas Compact Commission has been working with states and provinces to evaluate their idle- and orphan-well programs and identify useful regulatory tools and strategies to address this issue. In addition, in Oklahoma, the industry voluntarily takes responsibility for orphaned well sites and has invested over $132 million to clean up over 18,000 orphaned wells sites.

Finally, preventing wells from becoming orphaned in the future is complicated. States recognize this issue and are reviewing their programs, statutes, and rules to determine the best course of action to prevent the occurrence of these types of wells. States, like Oklahoma, are in the best position to address future orphaned wells, and as such, EPA should defer to the state. A major issue not addressed in the Proposal is various specific agreements, memorandums of understanding and plugging consent orders. Again, for EPA come in run roughshod over these existing arrangements would represent a step backwards. In addition, if EPA proposes requirements, it needs to provide detailed rationale for its authority to regulate the "emission sources" and why the states should not have primacy in addressing the issue. Producer Associations believe that EPA lacks authority regulate well bonding.

20. EPA Needs to Address Revisions to Section 111(d) Realistically.

While EPA indicates that it will separately propose revisions to Section 111(d), it describes its attitude about many of these issues in this proposal. The Producer Associations believe that this arcane section of the CAA that has been a backwater issue for decades needs to be reformed, but these reforms need to retain key aspects of the intent of Section 111(d) and must be realistic. Following are reflections on several points that EPA addresses in this proposal.

a. Timelines

In 2019, EPA developed revisions to the Section 111(d) process – 40 CFR Part 60 Subpart Ba. These changes were vacated by District of Columbia Circuit Court in *American Lung Association v the Environmental Protection Agency*. However, in EPA's discussions of its intent regarding revisions to Section 111(d) regulations, it is clear that it plans to use the framework of these vacated regulations in large measure in its future proposal. Among those provisions, EPA refers to the 24 month timeline for compliance with approved state regulations under EPA approved plans. Another timeline within the vacated regulations provides for states to have three years to develop their plans. EPA should retain a timeline of at least this length in its proposed Section 111(d) regulations. Regulatory development is already complicated and EPA indicates that it intends to create new mandates on the state planning process addressing EJ and community involvement actions that it wants addressed by states.

There are real consequences that result from EPA's timeline choices. For example, in comments on the current EPA proposal, the West Virginia Department of Environmental Protection observed:

> The estimated cost for West Virginia to develop and implement this proposed rulemaking with a 10-year timetable to issue air quality permits, is over $40 million annually. This estimate is approximately four times the current DAQ budget and includes 373 additional full time equivalent persons to be hired. Inflation was not accounted for in these estimates.
>
> The estimated cost based on the proposed timing (final compliance within two (2) years) is even more outrageous and is over $278 million annually. To achieve final compliance within a two-year timetable, the permitting actions would need to be completed within the first year. This estimate includes 2,708 additional full time equivalent persons to be hired; however, it does not include additional administrative and supervisory personnel to manage such an increase. For perspective, this is over 33 times the current staff of the WVDEP, Division of Air Quality. These costs do not include additional office space, office equipment such as computers and phones, uniforms, training, and other expenses that would be required. Inflation was not accounted for in these estimates.
>
> The state of West Virginia cannot assume this astronomical increase in expenses. Assuming the EPA were to fund this increase in expenses with annual grant money, the State would still face the reality of attracting and hiring over 2,700 additional personnel when it is already difficult for the state to compete with private industry for qualified candidates.

With approximately one million wells potentially subject to the Section 111(d) EG, these challenges will affect every oil and natural gas producing state.

b. Environmental Justice

EPA has clearly placed EJ on the agenda for its revisions to Section 111(d) regulations. EJ is a complicated issue. EPA has appropriately placed much of its concern about EJ on disadvantaged communities. However, as the Producer Associations discussed above, it can also be an issue for those that rely on the production of oil and natural gas for their energy or for royalties that sustain their farms or ranches or local communities. Drawing the intricate balances on these issues will be neither straightforward nor without conflict. These tasks to be borne by states will need clear and thorough guidance and training to undertake. Depending on how EPA crafts the requirements, states may need authorizing state legislation to implement them. EPA needs to fully set forth all of the factors when it proposes its revisions to Section 111(d) regulations.

c. Community Involvement

Community involvement can create similar issues. On the one hand, EPA wants to assure that local environmental problems have a legal pathway to resolution, a pathway that fairly balances the rights of the community with those of the operators. As the Producer Associations described above, EPA must also assure that the issues be subjected to the same standards on the part of community accusers as EPA would require operators to demonstrate when it initiates enforcement actions. EPA must also assure that the structure of the process does not unleash an expectation that local activists can access well sites that can be hazardous in an unsafe manner. Oil and natural gas producers must regularly deal with trespassers who climb on tanks for the view and drop lit cigarettes or joints into explosive liquids, who try to "surf" pump jacks, who have been known to stick their heads into tank openings and die of asphyxiation, who have tried to damage well sites to stop production. These illegal actions must not be facilitated in future EPA regulations. As with the EJ issue, EPA must frame its community involvement requirements such that states can implement them and recognize that additional state legislative action might be necessary.

d. State Authority to Consider Remaining Useful Life

The CAA guarantees states the right under Section 111(d) to alter EPA's EG based on the remaining useful life of the existing source when it states:

> Regulations of the Administrator under this paragraph shall permit the State in applying a standard of performance to any particular source under a plan submitted under this paragraph to take into consideration, among other factors, the remaining useful life of the existing source to which such standard applies.

Producer Associations are concerned that EPA intends to diminish or truncate this right. Its tone in the current proposal is troubling. For example, EPA states:

> To the extent that a State determines the presumptive standards in the final EG are not reasonable for a particular designated facility due to remaining useful life and other factors, the statute requires that the EPA's regulations under CAA section 111(d) permit States to consider such factors in applying a standard of performance. As such, the EPA's implementing regulations at 40 CFR 60.24a(e) allow States to consider remaining useful life and other factors to apply a less stringent standard of performance to a designated facility or class of facilities if one or more demonstrations are made. These demonstrations include unreasonable cost of control resulting from plant age, location, or basic process design; physical impossibility of installing necessary control equipment; or other factors specific to the facility (or class of facilities) that make application of a less stringent standard or final compliance time significantly more reasonable. The implementing regulations also clarify that, absent such a demonstration, the State's standards of performance must be "no less stringent than the corresponding" EG. See 40 CFR 60.24a(c).
>
> The EPA intends to provide further clarification on the general process and requirements for accounting for remaining useful life and other factors, including on the reasonableness aspect of the required demonstration, via a rulemaking to amend the implementing regulations in the near future. However, the EPA also recognizes that the oil and natural gas industry is unique such that the general approach to considering remaining useful life and other factors in the implementing regulations may not be an ideal fit. For example, the sheer number and variety of designated facilities in the oil and natural gas industry could make a source-specific

> (or even a class-specific) evaluation of remaining useful life and other factors extremely difficult and burdensome for States that want to undertake a demonstration. In addition, the presumptive standards for these designated facilities generally entail fewer major capital expenses compared with other industries for which EPA has previously issued EG under CAA section 111(d), and many of the proposed presumptive standards generally take the form of design, equipment, work practice, or operational standards rather than numerical emission limitations. Further, in proposing the presumptive standards for existing sources, the EPA has deliberately included certain flexibilities (*e.g.,* in cases of technical infeasibility) such that the EPA believes the presumptive standards should be achievable and cost-effective for a wide variety of facilities across the source category. Given these facts, the EPA believes that it would likely be difficult for States to demonstrate that the presumptive standards are not reasonable for the vast majority of designated facilities. The EPA is soliciting comment on these observations, and any other facts and circumstances that are unique to the oil and natural gas industry that could impact the remaining-useful-life-and-other-factors demonstration. The EPA is also soliciting comment as to whether the Agency should include specific provisions regarding the consideration of remaining useful life and other factors in this EG that would supplement or supersede the general provisions in the implementing regulations.

In particular, the Producer Associations are concerned that – while EPA admits states that have the right to distinguish requirement on remaining useful – EPA announces that it has prejudged the outcome when it states:

> Given these facts, the EPA believes that it would likely be difficult for States to demonstrate that the presumptive standards are not reasonable for the vast majority of designated facilities.

This inherent bias before EPA even proposes revisions to the Section 111(d) regulation suggests a stacked deck against the rights of states to make decisions that reflect the diverse operations in their jurisdictions.

e. EPA Needs to Maintain the Intent of Section 111(d)

As EPA observes:

> Over the last forty years, under CAA section 111(d), the agency has regulated four pollutants from five source categories (*i.e.*, sulfuric acid plants (acid mist), phosphate fertilizer plants (fluorides), primary aluminum plants (fluorides), kraft pulp plants (total reduced sulfur), and municipal solid waste landfills (landfill gases)).

As the Producer Associations related previously, the history of Section 111(d) demonstrates that it was intended to be used for a limited number of sources but its scope changed when courts ruled that greenhouse gases could be considered pollutants under the CAA. Moreover, the regulations governing the development of EG and state plans encourage EPA to use flexibility to reflect the differences between new and existing sources. Section 60.22a(b)(5) in the September 2019 version of 40 CFR Part 60 Subpart Ba states:

> The degree of emission limitation achievable through the application of the best system of emission reduction (considering the cost of such achieving reduction and any nonair quality health and environmental impact and energy requirements) that has been adequately demonstrated for designated facilities, and the time within which compliance with standards of performance can be achieved. The Administrator may specify different degrees of emission limitation or compliance times or both for different sizes, types, and classes of designated facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.

Clearly, the concept of developing EG under Section 111(d) and the subsequent state regulations relies on the model from Section 110 where new sources are subject to BSER or more aggressive new source requirements and existing ones to Reasonably Available Control Technology. EPA was granted and has embraced this approach in its limited past use of Section 111(d). However, the Producer Associations see that the current proposal as a clear attempt to circumvent these policies by EPA's actions in defining affected facilities and designated facilities in ways to limit subcategorization in a clearly diverse industry.

EPA needs to maintain the intent of Section 111(d). The purpose of existing source EG should be to create an equitable regulatory structure for the management of methane emissions from existing facilities, not to use the CAA as a thinly disguised effort to eliminate them through excessively costly regulations.

Producer Associations appreciate the opportunity to comment on EPA's Proposal. Members of the Producer Associations have been working closely with EPA for the past eleven years on the NSPS for the oil and gas industry and much progress has been made. Various aspects of the Proposal indicate more work needs to be done. From the beginning of Subpart OOOO and its progeny, the mantra of individual companies, many if not most constitute small business, is one size does not fit all. The Producer Associations invite and will seek interaction with EPA to promulgate regulations protect the environment, protect small business and are within the legal boundaries of the Clean Air Act.

Sincerely,

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