July 30, 2021

Re: Reducing Emissions of Methane and Other Air Pollutants from the Oil and Natural Gas Sector: Request for Information

Docket ID No. EPA-HQ-OAR-2021-0295

Supplement 1

The following Comments are submitted on the above-referenced request for information on behalf of the Independent Petroleum Association of America (IPAA). IPAA represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be the most significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 90 percent of American oil and gas wells, produce 54 percent of American oil and produce 85 percent of American natural gas.

Some of the comments submitted here have been previously submitted to prior dockets in connection with the development of Subpart OOOOa and subsequent reconsiderations of it. These comments were submitted by IPAA, American Exploration & Production Council ("AXPC"), Domestic Energy Producers Alliance ("DEPA"), Eastern Kansas Oil & Gas Association ("EKOGA"), Illinois Oil & Gas Association ("IOGA"), Independent Oil and Gas Association of West Virginia, Inc. ("IOGA-WV"), 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"), Pennsylvania Independent Oil & Gas Association ("PIOGA"), Texas Alliance of Energy Producers ("Texas Alliance"), Texas Independent Producers & Royalty Owners Association ("TIPRO"), and West Virginia Oil and Natural Gas Association ("WVONGA") (collectively, "Independent Producers").

The material submitted in these comments supplements information supplied in earlier comments dated July 29, 2021. These comments address additional issues. They include public reports and studies that describe methane emissions related to oil and natural gas production. These comments will specifically focus on aspects of the reports related to low production wells and small business operators. Additionally, these comments address the regulatory development process with regard to reconsideration of Subpart OOOOa and emissions guidelines under Section 111(d).

Public Reports and Studies

<u>Environmental Defense Fund PermianMAP</u>

The Environmental Defense Fund (EDF) recently released a body of information on methane monitoring from the Permian Basin. It is a mixture of aircraft flyovers and ground remote monitoring. EDF has consistently attempted to target low production wells in its methane emissions analyses. In this instance, it continued this targeting. However, its results support the basic arguments that have been made by the Independent Producers over the past several years. The EDF presentation includes the following statement:

> Results included: 35% of methane plumes emanated from midstream facilities; 79% from tanks; and among marginal wells, 17% of complex sites (with multiple pieces of equipment) had emissions, while none were detected at "pump-jack only" sites.

The 79% of emissions from tanks are divided between vents (46.38%) and thief hatches (32.77%). The marginal wells sites with emissions (complex sites) showed emissions from their storage tanks.

This new data demonstrates the validity of assessments made from other studies submitted by environmental groups where a parsing of the information to evaluate low production wellsites (marginal wells) also shows that process equipment at the sites are not the sources of emissions; storage tanks are.

Importantly, these results further demonstrate that a costly, complicated optical gas imaging (OGI) leak detection and repair (LDAR) program like the requirements in Subpart OOOOa is not appropriate for low production wells. Since a Subpart OOOOa program would not find emissions from the processing equipment and since the sources of emissions from tanks are known, a cost effective alternative would be more appropriate. An LDAR program that would concentrate on maintaining tank seals and keeping thief hatches closed would be sufficient. As far as the tank vents are concerned, the issue is whether the emissions would even exceed the EPA threshold for regulation. This issue was addressed in the Independent Producers' previous comments as follows:

> Storage tanks will have emissions. However, they are intended to have emissions in order to assure their safe operations. Subpart OOOO requires the capture of vapors from tanks unless they fall below a threshold where vapor capture is not cost effective. As Subpart OOOO tanks populate the universe of oil and natural gas production facilities, these emissions will be captured and managed. However, the pool of low production wells now in existence predate Subpart OOOO. At the same time, the turnover of production in these wells will be far below their design rates and therefore the emissions will be much smaller. Limited data suggest that emissions from these wells fall well below the threshold for regulation. The following table from the EPA document, *Control Techniques Guidelines for the Oil and Natural Gas Industry*, published as a part of EPA's action in October 2016 presents storage tank emissions based on production levels. Its information is telling.

Table 4-2. Average Oil and Condensate Production and Storage Vessel Emissions per Production Rate Bracket[16]

Production Rate Bracket (BOE/day)[a]	Oil Wells: Average Oil Production Rate per Oil Well (bbl/day)[b]	Oil Wells: Crude Oil Storage Vessel VOC Emissions (tpy)[c]	Gas Wells: Average Condensate Production Rate per Gas Well (bbl/day)[b]	Gas Wells: Condensate Storage Vessel VOC Emissions (tpy)[c]
0-1	0.385	0.083	0.0183	0.038
1-2	1.34	0.287	0.0802	0.168
2-4	2.66	0.570	0.152	0.318
4-6	4.45	0.953	0.274	0.573
6-8	6.22	1.33	0.394	0.825
8-10	8.08	1.73	0.499	1.04
10-12	9.83	2.11	0.655	1.37
12-15	12.1	2.59	0.733	1.53
15-20	15.4	3.31	1.00	2.10
20-25	19.9	4.27	1.59	3.32
25-30	24.3	5.22	1.84	3.85
30-40	30.5	6.54	2.55	5.33
40-50	39.2	8.41	3.63	7.59
50-100	61.6	13.2	5.60	11.7
100-200	120	25.6	12.1	25.4
200-400	238	51.0	23.8	49.8
400-800	456	97.7	44.1	92.3
800-1,600	914	196	67.9	142
1,600-3,200	1,692	363	148	311
3,200-6,400	3,353	719	234	490
6,400-12,800	6,825	1,464	891	1,864
> 12,800[d]	0	0	0	0

Minor discrepancies may be due to rounding.
[a] BOE=Barrels of Oil Equivalent
[b] Oil and condensate production rates published by U.S. EIA. "United States Total Distribution of Wells by Production Rate Bracket."
[c] Oil storage vessel VOC emission factor = 0.214 tpy VOC/bbl/day. Condensate storage vessel VOC emission factor = 2.09 tpy/bbl/day.
[d] There were no new oil and gas well completions in 2009 for this rate category. Therefore, average production rates were set to zero.

In its document, EPA makes the following recommendation for a model Reasonably Available Control Technology ("RACT") regulation for existing facilities:

> In summary, we recommend the following as RACT for storage vessels in the oil and natural gas industry:
>
> > (1) RACT for Condensate Storage Vessels: Reduce emissions by 95 percent continuously from condensate storage vessels with a PTE > 6 tpy of VOC; or demonstrate (based on 12 consecutive months of uncontrolled actual emissions) and

> maintain uncontrolled actual VOC emissions from storage vessels with a PTE greater than or equal to 6 tpy at less than 4 tpy.
>
> (2) RACT for Crude Oil Storage Vessels: Reduce emissions by 95 percent continuously from crude oil storage vessels with a PTE > 6 tpy of VOC; or demonstrate (based on 12 consecutive months of uncontrolled actual emissions) and maintain uncontrolled actual VOC emissions from storage vessels with a PTE greater than or equal to 6 tpy at less than 4 tpy.

The table demonstrates that emissions related to the average low production oil well (2.8 barrels/day) would be on the order of 0.57 tons/year ("tpy"). The assessment of emissions from natural gas wells is based on associated gas condensate. Broadly, condensate is about 10 percent of natural gas production when it is present. Consequently, for the average low production natural gas well of 20 mcfd (about 3.3 barrel/day of oil equivalent), gas condensate would be about 0.3 barrels/day. The emissions associated with this production would be approximately 0.038 tpy.

Alternatively, to reach the 4 tpy EPA threshold for regulation, oil production would have to be over 20 barrels/day and gas condensate over 30 barrels/day. Each of these is greater than the definition of a low production well and significantly over the production of an average low production well.

Clean Air Task Force-Ceres Report

In June 2021, the Clean Air Task Force (CATF) and Ceres released a report, *Benchmarking Methane and Other GHG Emissions Of Oil & Natural Gas Production in the United States* (Ceres Report), that presents information gleaned from the US *Inventory of U.S. Greenhouse Gas Emissions and Sinks* (USGHGI). CATF and Ceres characterize this report as:

> A first-of-its-kind analysis from Ceres and the Clean Air Task Force provides investors, operators, natural gas purchasers, policymakers and regulators with the data needed to directly compare relative emissions intensity and total reported methane, carbon dioxide, and nitrous oxide emissions for nearly 300 U.S. oil and gas producers. The results reveal dramatic variability between companies and basins.

This is certainly a lofty assessment of the information that the report provides. The CATF goes further by targeting small businesses with the following statement:

> The report demonstrates that many small oil and gas operators have an outsized impact on total industry greenhouse gas emissions.

This type of rhetoric is consistent with prior CATF efforts as a part of a group of environmental commenters that have submitted numerous statements trying to tar low production wells and the small businesses that operate them with regard to EPA's actions to address reconsideration of Subpart OOOOa.

In a larger sense, the Ceres Report demonstrates the challenge of using publicly available information without understanding its limits. The USGHGI presents thousands of data points but their usefulness is constrained by the limits of their underlying purpose and creation. The Ceres Report first presents an array of information that it has pulled from the USGHGI by company, by basin of operation, by type of emissions source. Then, it explains that these data are limited by the fundamental constraints of the USGHGI. Fundamentally, the problem with the Ceres Report is that the USGHGI was never intended to provide emissions information with the accuracy or certainty that the Ceres Report suggests it provides.

A key finding of the Ceres Report illustrates the nature of the limitations. The Ceres Report observes that:

> Pneumatic controllers were the largest source of total reported production-segment methane emissions, making up 54% of total reported methane emissions.

This is a significant point, partly because it also bears on the reported emissions numbers from smaller operators. At issue is the quality of the reported numbers. It takes emissions factors developed for a general understanding of industry operations and applies them inappropriately because they never had the precision for this new purpose.

Pneumatic controllers have historically been a large component of oil and natural gas production emissions. EPA addressed pneumatic controllers as a part of the Subpart OOOO NSPS by requiring that low bleed controllers by utilized. This choice reflected the need to eliminate high bleed controllers as a part of better methane emissions management. Since late 2011, Subpart OOOO has compelled these changes and many facilities used them prior to Subpart OOOO and many companies have replaced controllers since then. However, pneumatic controllers continue to show as a large element of the USGHGI. Much of this is a result of the reporting of existing sources and the use of intermittent controllers.

The basic process of reporting emissions for the USGHGI involves multiplying a component (such as a pneumatic controller) by an emissions factor (EF). Consequently, the validity of the EF is an essential issue. For intermittent controllers, the validity of the EF has been a recurring controversial debate. Fundamental aspects of the EF include the frequency of the intermittent activity and the magnitude of emission during any controller activation. The current USGHGI intermittent controller EF was essentially developed in the mid-1990s by the Gas Technology Institute (GTI) and then adopted by EPA for the USGHGI. When it was developed there was no USGHGI, not even one on the horizon. The EF was never formulated for the purpose that it is now being used.

A review of reported USGHGI emissions by several of the small business companies tarred by the Ceres Report for high methane emissions shows that they reported large numbers of intermittent pneumatic controllers. If the Ceres Report wants to use the USGHGI to create comparisons between companies or highlight those with significant emissions, it needs to further assess the quality of the data. A review of the controversies surrounding the intermittent pneumatic controller is illustrative of the complexity of this challenge.

First, it is important to know the basis for the USGHGI intermittent controller EF. EPA's current Greenhouse Gas Reporting Program (GHGRP) emission factor for natural gas-driven intermittent vent pneumatic controllers represents an average emission rate of 19 pneumatic controllers, 7 measured in the US and 12 measured in Canada during two field campaigns in the

1990’s. The 7 US pneumatic controllers had an average emission rate of 21.3 standard cubic feet per hour (SCFH) with a range of 8.8 to 39.6 SCFH. The 12 Canadian pneumatic controllers had an average emission rate of 8.8 SCFH with a range of 0.5 to 29.0 SCFH. Combined, these 19 intermittent pneumatic controllers had an average emission rate per intermittent pneumatic controller of 13.5 SCFH. The small total sample size (19 measurements) and high variability of the measurements suggests that the EPA mandated average emission factor of 13.5 SCFH warrants reevaluation.

A number of studies have been conducted to address the accuracy of the current intermittent controller EF. In 2014, the Oklahoma Independent Petroleum Association (OIPA) evaluated 659 intermittent controllers at 190 wells[1]. Its results produced an EF of 0.33 SCFH. In 2016, EPA conducted a study[2] that produced the following information:

> In the fall of 2016, a field study was conducted in the Uinta Basin Utah to improve information on oil and natural gas well pad pneumatic controllers (PCs) and emission measurement methods. A total of 80 PC systems at five oil sites (supporting six wells) and three gas sites (supporting 12 wells) were surveyed, and emissions data were produced using a combination of measurements and engineering emission estimates. Ninety-six percent of the PCs surveyed were low actuation frequency intermittent vent type. The overall whole gas emission rate for the study was estimated at 0.36 scf/h with the majority of emissions occurring from three continuous vent PCs (1.1 scf/h average) and eleven (14%) malfunctioning intermittent vent PC systems (1.6 scf/h average). Oil sites employed, on average 10.3 PC systems per well compared to 1.5 for gas sites. Oil and gas sites had group average PC emission rates of 0.28 scf/h and 0.67 scf/h, respectively.

These studies and others have shown that properly functioning intermittent controllers result in emissions far lower than the EF used in the USGHGI. EPA is well aware that the intermittent controller EF was created based on a small sample of controllers. Nevertheless, EPA has yet to make any serious effort to revise the EF to a more realistic value or provide for a more robust assessment of driving forces that affect the EF.

For example, in the context of low production wellsites, studies have not been made to assess whether the frequency of intermittent controller operation changes as production decreases and valves move less often. Malfunctioning intermittent controllers are known to increase emissions because releases occur more often, but the reverse could be true when the frequency is reduced in properly functioning intermittent controllers.

These fundamental issues regarding the EF for intermittent pneumatic controllers points to the problem inherent in the Ceres Report. Because it relies on calculations that are flawed, its assertions – no matter how robustly Ceres parsed the reports and recast them – cannot be validated, cannot be used for the purposes the Report attempts to set forth. Correspondingly, these same inherent problems prevent these judgments from bearing on the regulatory process.

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[1] Pneumatic Controller Emissions from a Sample of 172 Production Facilities

[2] Assessment of Uinta Basin Oil and Natural Gas Well Pad Pneumatic Controller Emissions

Reconsideration and Existing Source Emissions Guidelines

<u>Subpart OOOOa Reconsideration</u>

IPAA addressed the broad questions of Subpart OOOOa New Source Performance Standards (NSPS) reconsideration in its earlier comments, dated July 29, 2021, but they are restated here.

In 2020, EPA revised Subpart OOOOa through a series of technical revisions. Cast under the light of the volatile organic compounds (VOC) and methane debate, these changes now need to be visited for what they are – necessary modifications of the Subpart OOOOa NSPS to address issues resulting from its hasty development. It is important to recall that both Subpart OOOO and OOOOa were developed under intense time pressures that precluded the necessary deliberation that should accompany such significant regulatory actions.

Subpart OOOO was driven by a consent decree that compelled EPA to complete its actions on a compressed schedule. While EPA was able to use technologies that had largely been developed and used in voluntary programs, its expedited rulemaking led to a number of essential revisions that have been made since completion of the NSPS.

Subpart OOOOa presents a similar but more problematic history. The timeline for Subpart OOOOa was driven by political pressures to complete it prior to the end of 2016. Because Subpart OOOO had addressed the large components of oil and natural gas production emissions – storage tanks, reduced emissions completions for hydraulically fractured natural gas wells, and pneumatic controllers – Subpart OOOOa targeted small and less thoroughly understood technologies. Some of these like pneumatic pumps and reduced emissions completions for fractured oil wells followed the Subpart OOOO path of utilizing known technology. But, the Leak Detection and Repair (LDAR) component plowed new ground. Its structure led to a contentious debate framed by two key factors. The first relates to the choice of the LDAR technology, and optical gas imaging (OGI) requirement primarily relying on Forward Looking Infrared (FLIR) cameras. FLIR cameras are both costly and complicated, creating an expensive LDAR program. The second factor relates to a last minute change in the final 2016 NSPS, largely driven by political pressure from environmental lobbyists, to change the scope of the LDAR program. Proposed as a large facility based technology that excluded low production wells, the final NSPS expanded its scope to cover all wellsites. But, it never adjusted the technology structure to reflect its application to low production wells.

The 2020 technical reconsideration regulations addressed both of these issues. With regard to the LDAR technology, EPA attempted to create some pathways for the use of newer, better technologies. These pathways are constrained by the CAA Alternative Means of Emission Limitation (AMEL) structure. Designed for applications to stationary sources such as factories that operate for multiple decades and have a consistent production rate, it is characterized by a process that is long and complicated. AMEL use for oil and natural gas production presents different challenges to reflect the large number of operations. Nevertheless, the opportunity to allow for new, better technology is essential.

Similarly, the 2020 regulations addressed the issue of low production wells. EPA ultimately recognized that its LDAR program designed for large production operations was not appropriate for low production wells. Low production wells are defined as those producing 15 barrels/day of oil equivalents (BOE) or less (90 mcfd of natural gas or less). When EPA created its Control Techniques Guidelines (CTG) for existing sources of VOC in ozone nonattainment areas, it excluded low production wells from its model LDAR regulations. EPA chose a similar approach for the OOOOa NSPS. Since the NSPS applies to new and modified sources, EPA recognized that wellsite production would decline over time. The regulatory revisions now provide that when wellsite production falls to 15 BOE/day, the NSPS LDAR no longer applies.

The implications of this low production well change have been overstated. EPA's model low production wellsite is based on two wells per site or less. However, with the expansion of advanced drilling techniques using hydraulic fracturing and horizontal well bores, most new wellsites are populated by many wells with newer ones having ten to twenty wells per site. Only about 25 percent of new wellsites are one to two wells. It will be a long time before a wellsite with ten to twenty wells will deplete to 15 BOE/day or less, assuming that they remain economic at those low production levels.

The issue of low production wells at existing facilities is a very different and far more significant one. This is a key reason why the debate over VOC or methane regulation has been so significant. Now, EPA's challenge is to separate the politically intense atmosphere related to VOC from the sound technical decisions that reflect information demonstrating the shortcomings of the Subpart OOOOa regulations and that were embraced in the 2020 regulatory actions.

Section 111(d) Existing Source Emissions Guidelines

The Section 111(d) emissions guidelines development process has been little used since it was created in the 1970 CAA Amendments. It has never been used for an industry with the broad scope of oil and natural gas production – an industry that is operating about one million wells in the United States. Its basic regulatory structure was created in 1975 and has not been amended extensively since. The 2019 Affordable Clean Energy regulations did modify the Section 111(d) process, but these regulations were vacated in January 2021. Nevertheless, the underlying Section 111(d) regulations provide EPA with the flexibility it needs to develop a workable set of existing source emissions guidelines for oil and natural gas production facilities.

The oil and natural gas production industry comprises approximately one million wells, roughly 500,000 oil wells and 500,000 natural gas wells. Of these, about 750,000 are low production wells, again about half oil wells and half natural gas wells. Of the remaining 250,000 wells, most have been drilled since Subpart OOOO was effective. By the time Section 111(d) emissions regulations are finalized, wells drilled after 2011 will likely comprise all of the non-low production existing wells in the US inventory. These are significant factors as EPA considers creating its Section 111(d) emissions guidelines. Low production wells are very different from the large new sources that Subparts OOOO and OOOOa regulate. EPA has never had an accurate emissions profile for low production wells and the need to understand their emissions profile is more critical than ever in the Section 111(d) process.

A key aspect of the Section 111(d) development process is set forth in 40 CFR 60.22, Publication of Guideline Documents, Emission Guidelines, and Final Compliance Times. In subsection (b)(5), it states:

> An emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities, and the time within which compliance with

> emission standards of equivalent stringency can be achieved. The Administrator will specify different emission guidelines 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.

The first essential element of this subsection is its explicit statement that EPA should specify "…different emission guidelines 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".

The oil and natural gas production industry is characterized by a diverse makeup of type of production and size of operations among other things. All oil and natural gas wells decline over time and ultimately become low production wells before they are plugged. These different sizes of operations result in both differences in the extent of emissions from the operations and the economics of managing these emissions. Similarly, there are different types of operations. Crude oil wells differ from natural gas wells. Heavy crude oil differs from light crude oil. Oil wells with associated gases differ from those where associated gas is minimal. Natural gas wells with natural gas liquids differ from dry natural gas wells. Other factors such as the presence of hydrogen sulfide (sour gas) that can compel different management could bear on the emission profile. Wells developed under the 2012 Subpart OOOO regulations will differ from those developed under the 2016 Subpart OOOOa and 2020 Subpart OOOOa regulations.

In fact, the differences with regard to low production wells have been more clearly documented in the course of a study by the Department of Energy (DOE). Because the question of low production well emissions profiles has been so contentious, DOE initiated a study, Quantification of Methane Emissions from Marginal Oil & Gas Wells. This study is currently underway with a target completion in 2021, having been delayed by the COVID pandemic. The study has identified factors that could affect the emissions profile of marginal wells. The following table from study briefing materials provides the identified differentiators:

Key Differentiators

	Categories			
Main Product	Dry Gas	Wet Gas	Light Oil	Other*
Production Rate (BOE/day/site)	0-1	>1-4	>4-8	>8
Well Pad Size (Pieces of equipment)	Small (1)	Medium (2-3)	Large (4-5)	Extra-Large (>5)
Disposition of Associated Gas (oil wells)	Recovered	Vented	Combusted	Other/NA

* Other main products are CBM and heavy oil; these products represent a small portion of the survey responses.

These differentiators create a 48 element grid of subcategories of factors that can affect the emissions profile of low production wells. The DOE study is analyzing how these differentiators define the emissions profile of low production wells.

As EPA is developing its Section 111(d) emissions guidelines, it will be essential that it fully understands the information that the DOE study generates since it will be key to formulating a well-reasoned emissions profile.

A second essential element is the charge that EPA create "An emission guideline that reflects the application of the best system of emission reduction (considering the cost of such reduction) that has been adequately demonstrated for designated facilities…." While these terms generally track the description of the Best System of Emissions Reductions (BSER) in Section

111(b) for new and modified sources, EPA has clearly recognized that a different standard applies for existing sources in its 1975 Federal Register publication of the rules at 40 CFR 60 Subpart B. Adoption and Submittal of State Plans for Designated Facilities for several reasons. For example, it states:

> emission guidelines will reflect the degree of control attainable with the application of the best systems of emission reduction which (considering the cost of such reduction) have been adequately demonstrated for designated facilities [§ 60.21(e)]. As discussed more fully below, the degree of control reflected in EPA's emission guidelines will take into account the costs of retrofitting existing facilities and thus will probably be less stringent than corresponding standards of performance for new sources.

Low production wells are the most economically vulnerable component of America's oil and natural gas production industry. They are overwhelmingly operated by small businesses. A number of times over the past several years, low prices for these commodities, particularly natural gas, have triggered the Marginal Well Tax Credit that exists to support these wells in times of extreme economic vulnerability. Assessing the cost of control for Section 111(d) emissions guidelines, particularly for components like an LDAR program that imposes an ongoing operating cost will be critical issue for EPA. This issue has been addressed repeated in other comments because it is so pivotal.

Evaluations of emissions from marginal wells have consistently shown that the likely sources of large emissions are from tanks associated with production operations. The recent work in the PermianMAP project showed that process facilities had few if any emissions while the emissions related to marginal wells came from associated tank storage operations. These conclusions are consistent with other information from studies over the years. They also bring into sharp focus why the debate of the Subpart OOOOa LDAR program has been so contentious.

Because EPA developed the Subpart OOOOa LDAR program for large wells and later expanded it to low production wells, its cost effectiveness for low production wells has remained a debatable issue. The 2020 Subpart OOOOa reconsideration regulations addressed this inconsistency by providing an offramp from the LDAR program when new and modified wellsites under Subpart OOOOa deplete to 15 BOE/day and less. Its action tracked the EPA Control Techniques Guidelines for existing sources in ozone nonattainment areas. This is a rational approach that needs to be supported in the review of Subpart OOOOa.

However, the issue will arise in some form in the context of the development of new Section 111(d) emissions guidelines. EPA clearly has the authority and a directive in the 40 CFR 60 Subpart B regulations to recognize the distinctions between new and existing sources. Existing low production wells average about 2.5 barrels/day of oil and 24 mcfd of natural gas. These operations need emissions guidelines that reflect their limited production, limited emissions and limited resources. The expensive Subpart OOOOa LDAR OGI program is not necessary to address the storage tank emissions that dominate low production wellsites. These emissions will arise from limited emissions points – thief hatches, tank seals and safety vents. A maintenance program using olfactory, visual and auditory (OVA) inspections would, for example, address these types of emissions without imposing the excessive costs of the Subpart OOOOa LDAR regulations. Such an approach, or a similar one if one is necessary, is well within the structure and intent of the Section 111(d) emissions guidelines regulatory development framework.

A third essential element relates to the time frame for state actions in response to the published Section 111(d) emissions guidelines. Congress directed EPA to create a state regulatory approval process that tracks the Section 110 State Implementation Plan process. When EPA developed its 40 CFR 60 Subpart B regulatory structure, it was a simpler time. EPA created a state approval time period of 9 months. Like the federal government, state regulation development processes have grown more complicated and time consuming. Moreover, while some Section 111(d) emissions guidelines address a few sources, this Section 111(d) action will clearly affect a million sources distributed across oil and natural gas with differing factors that the state regulatory action must address. EPA created the authority to have an extended approval time for states in 40 CFR 60 Subpart B. EPA should use that authority to provide states with a multiyear development period similar to Section 110 for these Section 111(d) emissions guidelines.

Conclusion

As EPA now turns to its reconsideration of Subpart OOOOa and the creation of Section 111(d) emissions guidelines, it needs to recognize what existing data shows and the limits of the data for regulatory purposes. The EDF PermianMAP and the Ceres Report have been released now in an effort to influence a number of actions including EPA's forthcoming regulatory decisions. Both attempt to emphasize low production wells and small businesses. In the EDF materials, its information supports recommendations stated by IPAA over the past several years that low production wellsites do not need the Subpart OOOOa LDAR program because their emission profile is dominated by tanks and simpler LDAR management options can be applied. In the Ceres Report, its effort to suggest that small businesses should draw more attention is a false focus based on fundamentally flawed data from the USGHGI.

The Administration's decision to review the 2020 Subpart OOOOa technical regulations and to initiate development of Section 111(d) emissions guidelines will reopen discussions on a number of issues that have been under ongoing debate. Among these issues will be the impact of regulatory structures on low production wells. IPAA believes that cost effective regulations can be developed to manage methane emissions from oil and natural gas production facilities. For the past several years, the material initially used to develop the Subpart OOOOa regulations has been scrutinized and new material developed. The review of the 2020 Subpart OOOOa regulations and development of Section 111(d) emission guidelines provide an opportunity to craft a cost effective regulatory approach for both new and existing sources.

Sincerely,

Daniel T. Naatz
Executive Vice President