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

The following Comments are submitted on the above-referenced request for information on behalf of 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").

Overview

For over the past eleven years[1] IPAA has been actively engaged in working with the EPA to promulgate NSPS for the oil and natural gas sector that are cost-effective, reasonable and justified under the CAA. IPAA's message has been clear and consistent: EPA's "one-size-fits-all" approach to regulating the oil and natural gas industry is inappropriate and disproportionally impacts conventional operations, low production wells, and small businesses. IPAA has advocated for cost effective management of industry air emissions – Volatile Organic Compounds (VOC) and methane – and has a long history of participation in voluntary programs that are cost-effective. Unlike many industries, the oil and natural gas industry's "product" is essentially the same "pollutant" that EPA has sought to control. The oil and natural gas industry has a pure economic incentive to prevent every molecule of "pollutant" from escaping to the atmosphere. What IPAA has consistently sought is cost-effective regulations justified by the

[1] EPA proposed Subpart OOOO for the oil and natural gas sector on July 28, 2011.

authority entrusted to the EPA by the Clean Air Act (CAA), tailored to the unique aspects of the industry.

The deliberations regarding the structure of federal regulation of oil and natural gas production air emissions continue to evolve. Congress' recent action to pass a Congressional Review Act (CRA) resolution to rescind EPA regulations that changed the regulatory target to Volatile Organic Compounds (VOC) largely settles a recurring question in the regulatory structure. Oil and natural gas production regulations will now be largely directed to manage emissions using methane as the targeted emissions. Focusing on methane emissions is consistent with Executive Order 13990, "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis." This Executive Order directs the Agency to reduce emissions of methane and other air pollutants from new and existing sources in the oil and natural gas sector. Two predominant elements of those efforts will be reconsideration of technical changes to Subpart OOOOa (Oil and Gas Sector: Emissions Standards for New, Reconstructed, and Modified Sources) and the development of emissions guidelines under Section 111(d) of the CAA.

The debate over the choice of VOC or methane as the regulatory target has been intense and acrimonious, sometimes hyperbolic. Much of the tension related to the implications of the choice on the regulation of existing oil and natural gas wellsites. That debate is now over. The next steps must turn to the development of cost effective regulations.

Technical Reconsideration Regulations

The first issue will be whether action needs to be taken regarding the reconsideration of the Subpart OOOO and OOOOa New Source Performance Standards (NSPS). In 2020, EPA revised Subpart OOOOa through a variety of technical revisions. Cast under the light of the 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 2016 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 no fewer than three reconsideration rulemakings making essential revisions.

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 expand 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. Because AMEL anticipated application to stationary sources such as factories that operate for multiple decades and have a consistent production rate, AMELs are characterized by a process that is long and complicated. AMEL use for oil and natural gas production presents different challenges and opportunities to reflect the large number of operations and processes that change significantly over time. 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 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 apply 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 barrels/day of oil equivalent, the NSPS LDAR no longer applies. This action is appropriate whether the emissions target is methane or VOC.

EPA's decision to create the low production well offramp has been criticized because EPA has included in its explanation of the regulations estimates of the emissions resulting from the regulatory change. The implications of the offramp 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 barrels/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.

Section 111(d) Existing Source Emissions Guidelines

Since the regulatory target will again be methane, EPA will now be considering the development of emissions guidelines under Section 111(d) of the CAA. This will present EPA and States with different challenge in the context of oil and natural gas production facilities compared to past EPA actions for other industries.

Section 111(d) was written into the CAA to address what Congress perceived as a limited number of pollutants with a limited number of facilities. It applies to pollutants that are neither criteria pollutants nor hazardous air pollutants. The CAA structures to manage those pollutants have programs for both new and existing sources. For some, such as ozone nonattainment regulating VOC, the programs are intricate and extensive. The history of Section 111(d), until recently, bears out that its use would be rare. It had been used only 13 times since the CAA was enacted and prior to its application in the context of GHG. Seven of those thirteen times were related to its application in conjunction with the implementation of Section 129 with regard to solid waste incinerators.

The expansion of the scope of CAA to include greenhouse gases (GHG) changes the implications of the use of Section 111(d), particularly for oil and natural gas production facilities. Unlike other source categories that have been addressed by Section 111(d) with limited facilities, there are about one million existing oil and natural gas wells in the United States. Of these, about 750,000 are low production wells.

EPA's approach to emissions guidelines for oil and natural gas production will be an important test. The past use of Section 111(d) relied on subcategorization of existing facilities in the source category. This will be essential in crafting workable emissions guidelines for oil and natural gas production operations. Among the factors that can affect the emissions profile of oil and natural gas operations are whether the facility is dominated by oil production or natural gas, whether the oil is heavy or light, whether there is substantial associated gas or none, whether the natural gas well has natural gas liquids or is dry, whether the facility is only a wellhead or has storage. Similarly, the continuing decline of oil and natural gas production over time creates other regulatory challenges.

Additionally, the process for states to develop regulations needs to be examined and fixed. Regulations for the development of Section 111(d) date back to the mid-1970s. Currently, a state must adopt regulations related to Section 111(d) emissions guidelines in nine months. While this schedule may have been feasible in 1975, it is virtually impossible to meet in most if not all states under current regulatory development processes. Failure to meet the deadline could force EPA to develop a federal implementation plan where simply more time would result in a state program.

IPAA will supply additional information in subsequent submissions. However, in this submission, IPAA will include past comments related the development and revisions to Subpart OOOOa because these materials address an array of substantive issues regarding the nature of oil and natural gas production, the nature of low production wells, the implications of various technological decisions and emissions information related to low production wells.

These prior comments are included in this comment as appendices and are listed below:

Appendix A: Comments for Three Regulatory Proposals issued September 18, 2015:

1) Oil and Natural Gas Sector: Emission Standards for New and Modified Sources (80 Fed. Reg. 56,593)
2) Release of Draft Control Technique Guidelines for the Oil and Natural Gas Industry (80 Fed. Reg. 56,577)
3) Source Determination for Certain Emission Units in the Oil and Natural Gas Sector (80 Fed. Reg. 56,579)

The Comments provided in Appendix A were submitted on December 4, 2015, and will be subsequently referenced as "2015 Comments";

Appendix B: Environmental Protection Agency's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration at 83 Federal Register 52,056 (October 15, 2018)

The Comments provided in Appendix B were submitted on December 17, 2018, and will be subsequently referenced as "2018 Comments";

Appendix C: Environmental Protection Agency's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration at 83 Federal Register 52056 (October 15, 2018) – Supplemental Comments

The Comments provided in Appendix C were submitted on June 17, 2019, and will be subsequently referenced as "2019 Comments"; and,

Appendix D: Re: Environmental Protection Agency's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review at 84 Federal Register 50,244 (September 24, 2019) Docket ID No. EPA-HQ-OAR-2017-0757

And

Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration (October 29, 2018) Docket ID No. EPA-HQ-OAR-2017-0483

The Comments provided in Appendix D were submitted on June 3, 2020, and will be subsequently referenced as "2020 Comments".

Synopses of Significant Issues

A. There are about 1,000,000 existing oil and natural gas wells. Approximately 200,000 of these wells have been regulated under Subpart OOOO and, now, Subpart OOOOa. That number grows each year. Of the remainder, 750,000 are low production wells.

In 2017, there were about 1,054,000 producing oil and natural gas wells in the United States.[2] While this total has been roughly between 1,000,000 and 1,100,000 since about 2009, the distribution of wells changes. Oil and natural gas production is characterized by the reality that all oil and natural gas wells decline over time.

The Independent Producers addressed this reality in its 2018 Comments:

> While Subpart OOOOa primarily addresses new sources, it fails to recognize the preeminent reality of oil and natural gas production – all wells deplete and decline in production over time. The reality of oil and natural gas well depletion has been well recognized since oil and natural gas production began. The 1940 book, This Fascinating Oil Business, includes this description:

[2] United States Petroleum Statistics, 2017 Data, Published February 2019, Independent Petroleum Association of America.

> …The production of all wells in which gas is the chief expulsive force and which are produced to capacity declines rather rapidly. This decline is especially noticeable in the early stages, from the "initial production" through what is known as the "flush" period and is less noticeable after the "flush production" is gone and the well is on "settled production," but the decline continues just the same.
>
> If the well is producing at capacity the decline is quickly noticeable; if it came in at two thousand barrels a day, in six months it may be down to a thousand barrels and in a year to six hundred. If the well is allowed to produce only a part of its potential production the decline may not be noticeable for a long time; the decline in pressure will be slower, for one thing, and for another, a well allowed to produce only twenty barrels a day will probably behave much the same whether its full productive capacity is two thousand barrels or only two hundred. Sooner or later, however, the well will fail to make the twenty barrels or one hundred or whatever amount it has theretofore been producing, and from that time on its decline will be apparent. Unless it goes to water the well may produce for twenty or fifty or even seventy years, but each year it will produce less than the year before.
>
> Fields and individual wells vary greatly, but in general this year's production from a settled well produced to capacity will be from ten to thirty per cent less than last year's.[3]

Consequently, for oil and natural gas production to be maintained and grow, new wells must be drilled annually to replace wells where production has become uneconomic. From 2012 through 2017, approximately 155,500 wells were drilled. However, several of these years were during low commodity prices that reduced drilling activity. Approximately, 41,000 wells are projected to be drilled in 2018 and 2019. Another 64,600 wells are projected from 2020 through 2022.

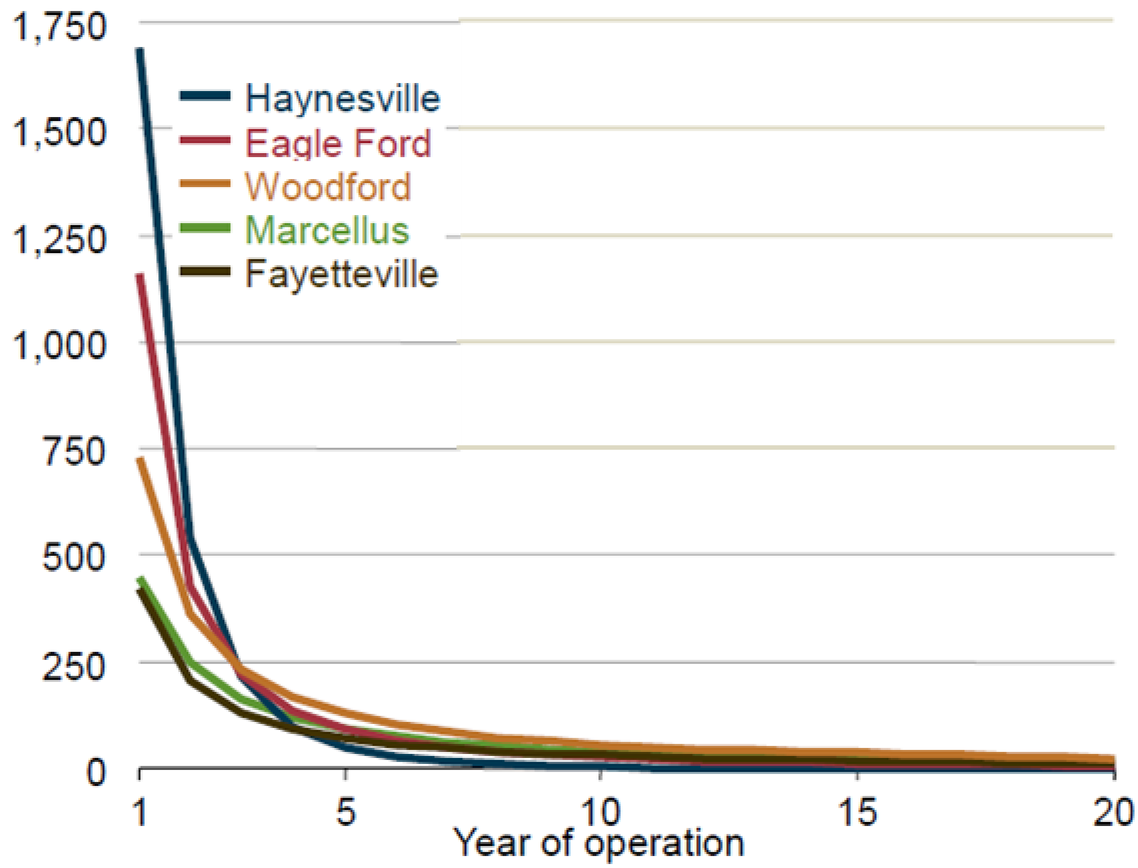
As a result, of the 1,000,000 oil and natural gas wells that will exist in 2022, approximately over 260,000 will have been drilled after the 2012 Subpart OOOO regulations were promulgated. The remaining wells would total about 740,000. In 2016, low production oil and natural gas wells in the U.S. totaled approximately 753,000[4].

These statistics demonstrate that currently about 200,000 oil and natural gas wells are already complying with the most effective regulatory requirements under the NSPS regulations and by the time a Section 111(d) existing source regulation could be promulgated, the only wells that would not be under some form of NSPS requirements would be low production wells.

[3] Ball, Max W., This Fascinating Oil Business, The Bobbs-Merrill Company, 1940, p. 142.
[4] United States Petroleum Statistics, 2017 Data, Published February 2019, Independent Petroleum Association of America.

B. Nationally, low production wells average about 2.5-2.8 barrels per day if they are oil wells and 20-24 mcfd if they are natural gas wells. Low production wells account for about 10-11 percent of US production or less depending on the source.

As described above, all oil and natural gas wells decline over their lifetime. However, most of this decline occurs during the first few years of production. The graphic below demonstrates that unconventional wells begin as high production operations, quickly decline, and ultimately become low production wells.



It is similarly important to understand that production rates from low production wells are well below the threshold of their definition. EPA – like other regulatory and tax provisions – defines low production wells as 15 barrels/day of oil equivalent or less[5]. However, average production rates for these wells in 2016 for oil wells was 2.8 barrels/day and for natural gas wells was 20 mcfd[6]. These are national averages but the volumes can vary widely by state. For example, in Kansas, an average low production oil well produces about 1.8 barrels/day[7]. And, in Pennsylvania, an average low production natural gas well produces about 6.1 mcfd[8].

[5] 15 barrels/day of oil is equivalent to 90 mcfd of natural gas.
[6] *Id*.
[7] 2015-2016 IPAA Oil & Gas Producing Industry in Your State ®, Published November 2016, Independent Petroleum Association of America
[8] *Id*.

Collectively, these wells contribute significantly to total American oil and natural gas production. The U.S. Energy Information Administration ("EIA") assessed the contribution of these wells to American production in 2016. It reported the following for oil wells:

> Despite each stripper well's small individual production, their large number ensures a significant contribution to total oil production. The production share of oil stripper wells has fallen from a high of 19% in 2008 to an estimated 10% in 2015. This decrease in share reflects the large increase of production volume from very prolific wells drilled in shale and tight oil formations with enhanced completion techniques.[9]

It reported the following for natural gas wells:

> Stripper wells, also known as marginal wells, individually produce small volumes of natural gas or oil but in aggregate have provided 11% to 15% of total U.S. oil and natural gas production over the past decade.
>
> …
>
> Stripper wells may have originally been high-volume wells, but through normal production declines now produce only small volumes. Because these wells usually have low ongoing maintenance costs, they are kept active and may continue to produce for many years, as long as they are economically feasible.
>
> Despite each stripper well's small individual production, in aggregate they make a contribution to total natural gas production. The production share of stripper gas wells has remained relatively constant over the past 25 years, rising from about 10% in 1991 to 15% in 2006–09 and dropping again to about 11% in 2015. The recent decrease in stripper wells' share of total production reflects the large increase in production from relatively prolific wells drilled in shale and tight gas formations with enhanced completion techniques.[10]

The overwhelming majority of these low production wells are small business operations. As the EIA report observes they "…may continue to produce for many years, as long as they are economically feasible." Consequently, the wells are put in jeopardy if their economic feasibility is impaired as a result of burdensome regulatory costs, particularly if the environmental benefits are not justified. The Keep It in the Ground environmentalists' tactic of pressing for methane regulation represents a strategy of imposing a burdensome regulatory program to eliminate these wells.

C. Oil and natural gas production systems account for about 1.2 percent of the US Green House Gases Inventory ("GHGI").

Much of the rationale for regulating oil and natural gas production methane emissions is a false perception that these emissions constitute a large and growing component of the GHGI. Neither is accurate.

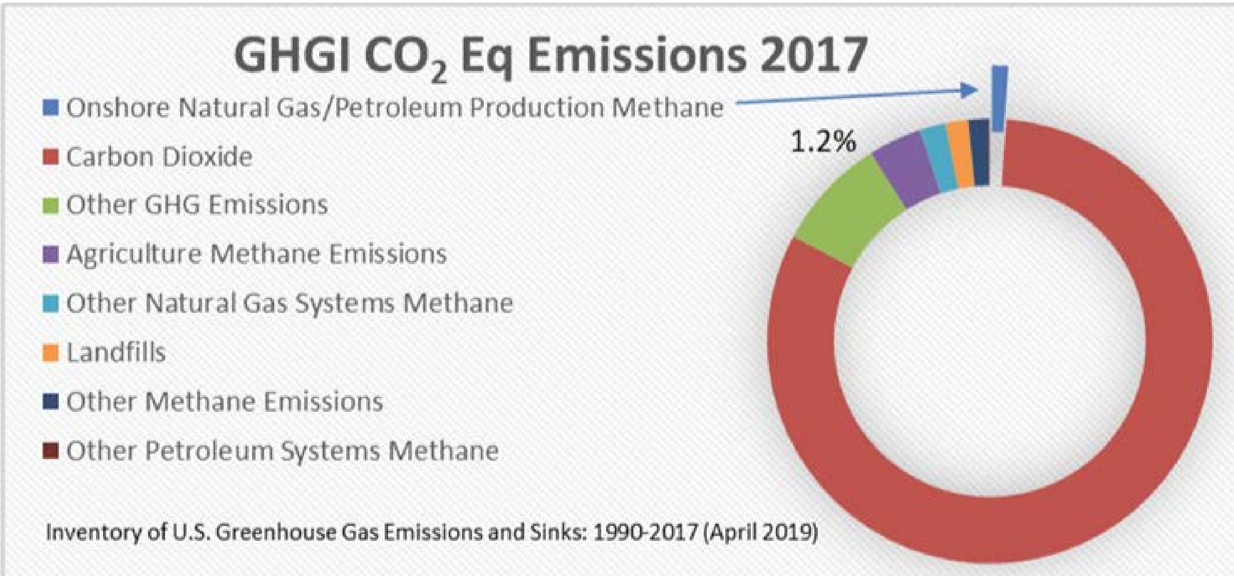
---

[9] Stripper wells accounted for 10% of U.S. oil production in 2015, https://www.eia.gov/todayinenergy/detail.php?id=26872#, Energy Information Administration, June 29, 2016

[10] Stripper wells accounted for 11% of U.S. natural gas production in 2015, https://www.eia.gov/todayinenergy/detail.php?id=27272#, Energy Information Administration, July 28, 2016

For the past several years, the share of methane emissions in the GHGI from the petroleum and natural gas systems production components has remained relatively constant despite dramatic increases in production of both commodities.

As the following graphic demonstrates, onshore natural gas and petroleum production methane emissions are about 1.2 percent of the 2017 GHGI. This percentage has stayed in the 1.1% - 1.2% range for the past several years as actual emissions of methane by the production segments have declined. Total onshore natural gas and petroleum production emissions in 2017 were calculated for the GHGI at 83.7 MMT CO_2 Eq. In 2019, they were 84.7 MMT CO_2 Eq.



Therefore, oil and natural gas production methane emissions are not a large component of the GHGI. Moreover, the 2012 Subpart OOOO and 2016 Subpart OOOOa NSPS regulate these emissions – and will continue to regulate these emissions under a VOC based regulation – as new facilities replace existing ones.

The second issue is whether growth in emissions will occur as a result of expanding production of American oil and natural gas. When EPA announced its intent to develop what eventually became Subpart OOOOa, it argued that additional regulations were necessary to prevent emissions growth. The Independent Producers challenged this view in its 2015 Comments based on EPA's own information as follows:

> In January 2015, the Administration announced its intent to initiate rulemaking to further reduce methane emissions from oil and natural gas systems, including the production sector.[11] Specifically, it announced a target of a 40-45 percent reduction in 2012 emissions by 2025. For the production and exploration segment of the oil and natural gas sector, additional regulations are unnecessary. As the Administration observed in its announcement:

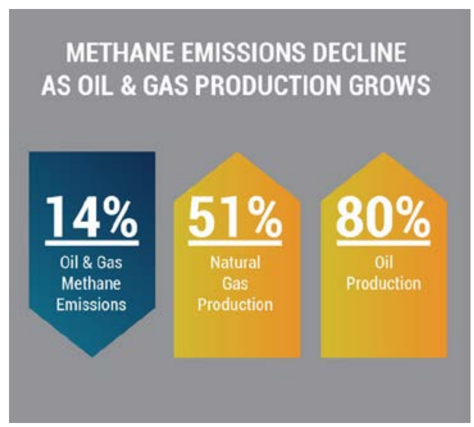
[11] Press Release, The White House, Fact Sheet: Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions (Jan. 14, 2015), *available at* https://www.whitehouse.gov/the-pressoffice/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

> In 2012, the Environmental Protection Agency (EPA) laid a foundation for further action when it issued standards for volatile organic compounds (VOC) from the oil and natural gas industry. These standards, when fully implemented, are expected to reduce 190,000 to 290,000 tons of VOC and decrease methane emissions in an amount equivalent to 33 million tons of carbon pollution per year.[12]

Over 99 percent of the EPA projected reductions occur from the exploration and production sector. In 2013, exploration and production emissions of methane were 71 million tons of CO2 equivalent. Consequently, by EPA's own numbers, the 2012 NSPS regulations will reduce emissions by 46 percent. This reduction exceeds the emissions target percentage of the production sector of the oil and natural gas industry.

EPA attempts to argue that its regulations are needed because methane emissions "are projected to increase by about 25 percent over the next decade if additional steps are not taken to reduce emissions from this rapidly growing industry."[13] Yet, this statement is wholly inconsistent with the experience over the past several years in the exploration and production sector of the industry. This segment has demonstrated that growth in production not only provides more clean-burning, GHG-reducing product, it has been done while reducing methane emissions….

For example, the unconventional production revolution began in the mid-2000s and even before the 2012 NSPS, companies were voluntarily implementing controls that reduced their emissions of VOC and methane. By the end of 2018, the EIA reported that 70% of American natural gas production and 60% of American crude oil production comes from these unconventional resources.



At issue then is the magnitude of the emissions from the 750,000 low production wells that produce roughly 10 percent of American oil and natural gas.

D. Emissions from low production wells are a small fraction of the GHGI.

Precise information on emissions of VOC and methane from low production wells remains elusive. Because these wells are generally operated by small businesses and produce at low volumes, data on emissions is limited. However, there is little reason to believe that emissions would be significant.

First, the physics that would drive emissions argue that they would be small. For gases within production facilities to move outside them, it takes a pathway and internal pressure to push the gas out. Wells are initially designed to operate at their initial production rates –

[12] *Id*.

[13] U.S. Environmental Protection Agency, Fact Sheet: EPA's Strategy for Reducing Methane and Ozone-Forming Pollution from the Oil and Natural Gas Industry (Jan. 14, 2015), *available at* https://www.whitehouse.gov/the-pressoffice/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

hundreds of barrels/day or thousands of mcfd. When they decline to low production wells, the equipment is much larger than it needs to be and the pressure inside it is far lower than it initially was. Most small oil wells need pump jacks to pull the oil out. Many natural gas wells need booster compressors to pull the gas out and increase its pressure to move it into gathering lines.

Second, the "emissions" are also the product. Consequently, every barrel or cubic foot that is emitted is also lost profit. For a natural gas well that produces 20 mcfd – or 6 mcfd – the emission of any significant amount would be a major income loss.

Third, if specific emissions sources are considered, even those raise questions. When EPA has looked at component emissions, three have drawn the greatest attention – pneumatic controllers, valves and storage tanks.

Emissions from pneumatic controllers result when natural gas is used to power the controller and is vented when controller action takes place. However, these controllers are designed for operations during the initial phases of production at the well. By the time a well declines to a low production status, the controllers do not routinely operate and venting is small if it exists.

Emissions from valves are similar. They arise as the valve moves to change the flow rate of oil or gas through it. By the time a well declines to low production status, these valves are fully open and do not move. Any gas would move through the pipe rather than through the tight spaces in a valve.

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		Gas Wells	
	Average Oil Production Rate per Oil Well (bbl/day)[b]	Crude Oil Storage Vessel VOC Emissions (tpy)[c]	Average Condensate Production Rate per Gas Well (bbl/day)[b]	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.

These factors would logically lead to a judgment that low production wells would not be a meaningful regulatory target. This was EPA's conclusion when it initially proposed Subpart OOOOa when it excluded low production wells from the scope of its cost Leak Detection and Repair ("LDAR") fugitive emissions program. However, under political pressure from the Keep It in the Ground environment lobby, it reversed its position and initiated an ongoing debate over emissions analyses that continues.

Because much of the rationale for regulating methane and for applying those regulations to low production wells hinges on perceptions created by studies done by Keep It in the Ground environmental lobbying groups – identified as the Joint Environmental Coalition ("JEC") in their comments regarding the Subpart OOOOa Reconsideration proposal, it is important to review them.

First, as a general matter, most of the studies are based on taking methane emissions data remotely for a few minutes to an hour. This data does not distinguish between fugitive emissions, allowable emissions or temporal events, such as liquids unloading. However, the data are then extrapolated to daily and annual emissions rates for these analyses.

Second, none of these studies are designed to evaluate low production wells. Rather, they take data and then find that some of the data are from low production wells.

There have been nine reports used to make arguments regarding the need for methane emissions management. Some of them related to regulatory costs; others related to emissions estimates. The Independent Producers addressed these reports in its 2019 Comments. The studies are:

A. *Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF Study) – Page 4 of 2019 Comments*

B. *Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras (Carbon Limits) – Page 5 of 2019 Comments*

C. *Waste Not: Common Sense Ways to Reduce Methane Pollution from the Oil and Natural Gas Industry (Waste Not) – Page 5 of 2019 Comments*

D. *Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites (Super-Emitters) – Page 6 of 2019 Comments*

E. *Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites (Lyon 2016) – Page 8 of 2019 Comments*

F. *Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin (Omara Marcellus 2016) – Page 9 of 2019 Comments*

G. *Assessment of methane emissions from the U.S. oil and gas supply chain (Assessment of Studies) – Page 12 of 2019 Comments*

H. *A technical assessment of the forgone methane emissions reductions as a result of EPA's proposed reconsideration of the 2016 NSPS fugitive emissions requirements for oil and gas production sites (Omara Appendix G) – Page 15 of 2019 Comments*

I. *Response to methane synthesis critiques (Hamburg) – Page 16 of 2019 Comments*

While the Independent Producers analyses looked generally at the reports, it specifically addressed the implications on low production wells. Following are brief observations with regard to the reports from the 2019 Comments; details are in the Comments.

Super-Emitters report: This study was used by EPA to remove the low production exclusion from Subpart OOOOa. It was purposely created to contrive the concept that low production wells emit excessively. It is a speciously generated abuse of analytical tools perpetrated as analysis. While the details are shown in the 2019 Comments, following are the key points that demonstrate its abuse of the limited data that was used to create it from the 2019 Comments:

> First, it shows emissions as a percentage of production rather than actual emissions. Thus, one mcf emitted out of ten mcf produced is 10 percent, but 50 mcf emitted out of 1000 mcf produced is 5 percent. As a result, it skews the perception of the data to imply that low producing wells are large emitters when they are not.
>
> Second, its production volumes are really sales volumes, not the amount extracted from the wellhead. Consequently, a "proportional loss rate" of 50 percent would be the calculated loss divided by the volume sold. If the percentage of loss were calculated based on extracted volumes, the 50 percent "proportional loss rate" would drop to 33 percent because the loss would be added to the sales volume to obtain the extracted volume.
>
> Third, it only shows data from the 70^{th} percentile of information. This excludes all of the virtually zero emissions that dominate the data.

> Fourth, it uses a logarithmic scale to present the data. One of the reasons to use logarithmic scales is to flatten curves to make them look more like straight lines.

Lyon 2016 report: This report was completed for the Environmental Defense Fund (EDF) using aerial data collection techniques. As stated in the 2019 Comments:

> Like other reports, this one was not structured to specifically address low production wells but it includes information that presents some useful insights regarding the low production wells it sampled. Of the 8220 well pads sampled, 4195 were low production wells (15 BOE/day or less), averaging 4.1 BOE/day. Of these 4195 low production wells, 57 had measurable emissions (1.3 percent). Of these, 37 had tank vent emissions, 8 had tank hatch emissions and 2 had both tank vent and hatch emissions. The remaining 10 (0.2 percent) had emissions from dehydrators, separators, trucks unloading oil from tanks, and unlit or malfunctioning flares. These emissions are not clarified regarding whether the emissions would be considered as fugitive or whether they are from allowable vents or normal operations (e.g., truck unloading). However, it does clearly call into question the benefits of an OGI based fugitive emission program to address the small percentage of low production wells that would be dealing with non-tank emissions.

Omara Marcellus 2016: This report included information on low production wells where a closer look reveals telling information regarding their emissions. As stated in the 2019 Comments:

> The report includes information from 19 conventional natural gas wells at 18 well pads, all of which are low production wells. The report suggests that emissions from these wells are proportionally higher than those from unconventional wells. Looking at the data more closely reveals some key facts.
>
> First, it is important to recognize that this report suffers from the same limitations as most others. Its emissions information is taken remotely for limited times and cannot be converted accurately to either daily or annual emissions. Consequently, using the emissions determinations in the report should not be considered as accepting them as accurate. As the information above indicates, subsequent reports show far lower emissions rates.
>
> Second, of the 19 conventional wells, onsite information related to an OGI survey is supplied for 18 of them. Of these 18, the average production rate was 13.08 mcfd with calculated emissions of 1.22 mcfd or 0.05 lbs/day. Translating this value to annual emissions, it would be 0.0092 tons/year.
>
> Third, of the 18 wells, the OGI information shows that 11 of them were characterized by having storage tank emissions from vents or hatches. Their average production rate was 13.79 mcfd with calculated emissions of 1.63 mcfd or 0.067 lbs/day. Translating this value to annual emissions results in a calculated value of 0.012 tons/year (tpy).
>
> Fourth, the current Volatile Organic Compound (VOC) Control Techniques Guidelines (CTG) document for oil and natural gas production facilities in ozone nonattainment areas recommends its Reasonably Available Control Technology

> (RACT) for storage vessels apply to storage vessels "…with a potential to emit (PTE) greater than or equal to 6 tpy VOC". The assumption in this report is that the methane content of the emitted vapor is 81 percent. Consequently, the annual emissions from the well sites with tanks would be approximately 0.019 tons/year. This is approximately 0.3 percent of the threshold for regulation in the current CTG.
>
> Fifth, to put a final perspective on the implications of this report with regard to low production wells, according to EPA, "A typical passenger vehicle emits about 4.6 metric tons of carbon dioxide per year…." or 5.07 tons per year. Applying the Greenhouse Gas Inventory Global Warming Potential to the emissions calculations for these tank-based well sites, it would take about ten of them to equal one typical passenger vehicle.

<u>Assessment of Studies</u>: This EDF report was released with great fanfare during the 2018 World Gas Conference to create the appearance of new data showing methane emissions from the oil and natural gas industry value chain. The report purports to show that emissions are far higher than those reported in EPA GHGI. The JEC then refers to this report as a linchpin of its arguments for changes to the Subpart OOOOa proposal, particularly with regard to the fugitive emissions program with a special focus on low production wells. However, probing its details provides a far different perspective. Some highlights from the Independent Producers 2019 Comments follow:

> This report is not new data. Rather, it is a reconstruction of prior data from others' studies. For example, it regurgitates the same information in the Super-Emitters study and adds some additional material from others.
>
> As a consequence, the report suffers from no certainty regarding the quality of its data by possibly exacerbating bias and inaccuracies through incompatible sampling and data collection methodologies. It accepts as accurate everything it receives and these data have glaring deficiencies.

Additionally, the report is replete with questionable choices and use of data. It relies on short term measurements that it extrapolates to daily and annual emissions. It ignores that its own aerial survey data found no observed emissions from pneumatic controllers and equipment leaks that should theoretically been high. It relies on the same specious percentage of sales approach as the Super-Emitters report. As the Independent Producers 2019 Comments conclude:

> All of these pieces point to a consistent conclusion regarding the validity of the Assessment of Studies report. It builds on data that is not consistent and then excludes data it does not want. But, the final aspect of its effort is telling. The key to the development of the Assessment of Studies is its statistical manipulation of its data to develop emissions values where it does not have data. Here are some important statements by the authors:
>
>> We assume our underlying emissions pdfs are lognormal, which is expected in a system where many independent random and multiplicative events can contribute to the occurrence and magnitude of emissions
>
> and

> Results from both tests applied to all of the datasets used directly in this work indicate that one cannot reject the null hypothesis that the site-level sample data arise from a lognormal population distribution

These are extremely weak arguments – "we assume … emissions pdfs are lognormal…."; "…one cannot reject the … hypothesis that the site-level … data arise from a lognormal population distribution."

If they are not lognormal distributions, the entire framework for the Assessment of Studies report becomes suspect. Correspondingly, looking at the nature of the site emissions data – with all of the flaws associated with the assumptions in evaluating that data – there is little to suggest it is a lognormal distribution.

These inadequacies and those described in the EID analysis of the report undermine the validity of the basis for arguing that the Assessment of Studies provides a basis for the fugitive emissions LDAR programs in Subpart OOOOa, particularly in their application to low production wells.

Collectively, the Keep It in the Ground lobby has used these reports to justify its targeting of low production wells. However, they do not make a plausible case. To the extent the Keep It in the Ground interests provide any viable data, it might indicate the most likely source of emissions is from storage tanks and not production equipment - however the volume of emissions is often below regulatory thresholds.

There are potentially profound issues related to using Section 111(d) as the regulatory framework for low production wells. The framework of regulation under the CAA is complex with an array of technology requirements. The most robust framework of these requirements unfolds in the Nonattainment provisions of the Act.

Because Nonattainment provisions address attainment of National Ambient Air Quality Standards ("NAAQS"), they must necessarily apply to both new and existing sources. Nowhere is this more complex than Ozone Nonattainment requirements regulating VOC and nitrogen oxides. State Implementation Plans ("SIPs") must create regulations to manage emissions of these ozone precursors and the Act specifies action steps that must be taken. The "budget" of emissions must be reduced over time toward ultimate attainment of a NAAQS that has continued to decrease over the past decades.

For new sources, Congress directed that they must be subject to a Lowest Achievable Emissions Rate ("LAER") standard – a standard conceivably more rigorous than NSPS. At the same time, it recognized that existing sources needed regulations that reflected a greater sense of cost effectiveness and established RACT. The process is involved and linked to the SIP process. EPA described RACT in the context of oil and natural gas production facilities as follows:

> The EPA has defined RACT as the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility. The General Preamble Supplement (September 17, 1979, 44 FR 53761), goes on to indicate that RACT for a particular source is determined on a case-by-case basis, considering the technological and economic circumstances of the individual source. In evaluating economic feasibility for RACT determinations, the EPA

> gives significant weight to economic efficiency and relative cost-effectiveness. The EPA has not established universal decision criteria for technological and economic feasibility that would apply in every case, and did not establish decision rules that would have restricted the cost consideration in determining whether an emissions control is considered "cost effective." Therefore, all RACT determinations are considered case-by-case determinations.
>
> The Oil and Gas CTG contains recommended controls that states may readily adopt, subject to EPA approval, for groups of covered sources. However, a state may also consider the uniqueness of a specific source's operations in evaluating whether the recommended controls are RACT for that source. The air agency should provide EPA with the information supporting the source-specific determination of RACT for each source. This demonstration could take into account cost effectiveness. Where the EPA determines that the air agency has shown that an alternative to the controls recommended in the CTG satisfies the requirements for RACT, the EPA will propose to approve the RACT demonstration.[14]

This determination carries with it two key points. First, the technology is reasonably available and cost effective in the context of an existing facility. Second, a state can develop its own regulatory approach rather than use the EPA model regulatory approach.

While Section 111(d) uses a theoretically similar approach – the development of emissions guidelines followed by a form of state implementation plans – it has never been used for controlling the number of facilities that will be involved in oil and natural gas development. Nor have Section 111(d) emissions guidelines ever been developed in the intense political crucible that surrounds the methane emissions debate. The mischaracterizations of emissions information by Keep It in the Ground environmentalists have tainted the perception of the emissions challenges.

Moreover, Section 111(d), however, uses a different technology basis than nonattainment. Section 111 develops BSER technology for new sources and that decision becomes the basis for existing sources under Section 111(d). Section 111(b) uses a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. Arguably, this means that a number of factors related to technology demonstrations, costs, energy and other elements. However, Section 111(b) addresses these issues in the context of new sources or sources being modified. It is not the same test as RACT; it is based on investments to be made in something new, not something that has been in operation.

Section 111(d), while it applies to existing sources, must use the same BSER basis. States are allowed to make some individual adjustments based on the remaining existing life of a facility, but there is little additional definition or Congressional guidance on what scope of flexibility is allowed.

[14] "Implementing Reasonably Available Control Technology Requirements for Sources Covered by the 2016 Control Techniques Guidelines for the Oil and Natural Gas Industry", EPA Memorandum, October 20, 2016

The conjunction of these factors – use of BSER and limited state flexibility to alter the technology – is particularly significant for oil and natural gas production facilities. Because oil and natural gas production operations decline over time, cost effectiveness judgments that are made as a part of a new source technology determination will not be the same. While the cost of the technology will remain the same, its application at new source production levels of hundreds of barrels/day of oil or thousands of mcfd of natural gas is a very different burden for an average low production oil well at 2.8 barrels/day or natural gas well at 20 mcfd.

Keep It in the Ground environmental lobbyists saw this reality as a pathway to shut down hundreds of thousands of low production wells when Section 111(d) is applied nationwide without the ability to alter its new source technology mandates.

Most of the regulations under Subpart OOOO and Subpart OOOOa involve capital equipment as a part of the new facility – vapor capture units on storage tanks, low bleed pneumatic controllers – or are related to actions taken during initial production – reduced emissions completions for hydraulic fractured oil and natural gas wells. However, the LDAR requirements are ongoing operating costs. The LDAR program is required on a regular basis, currently twice per year, and its costs remain the same. When EPA developed its structure for these requirements, they were based on high production facilities. In the Subpart OOOOa proposed regulations, low production wells were excluded; therefore, the impact on those wells were not a part of the cost effectiveness calculations. In reality, the cost impact on low production wells is far different, far more burdensome and far more economically threatening.

For this reason, Keep It in the Ground environmental lobbyists have tried to craft arguments suggesting LDAR requirements can be easily absorbed by oil and natural gas production facilities, but their own materials demonstrate that the regulations do not. The two key studies that the JEC used for its arguments on cost effectiveness of LDAR programs are the ICF Study and Carbon Limits. The Independent Producers addressed each in its 2019 Comments.

For the ICF Study it stated:

> This report funded by EDF created an array of cost effectiveness calculations in \$/mcf based on a series of critical assumptions. Since its completion, EDF and other members of the JEC have touted it as demonstrating that methane emissions can be reduced with technologies that only cost cents per day. While aggregating all of the cost effective technologies with the cost ineffective technologies might produce such a result, individual technology options do not. Equally significant are the EDF assumptions of the value of natural gas in calculating the benefits of regulations and the efficiency of the requirements. These are particularly important in the context of the fugitive emissions proposals.
>
> EDF concludes that a quarterly fugitive emissions program for natural gas wells would recover 264 mcf/y using a 60 percent recovery rate on emissions of 440 mcf/y and have a cost burden of \$7.60/mcf without recovery benefits and \$2.52/mcf with recovery.
>
> Putting this evaluation in some context changes the perspective. First, looking at the emissions and recovery quantities on a daily basis shows them to be 0.72 mcfd and 1.2 mcfd, respectively. These are small volumes for even the average well.

> EDF does not indicate the average production rate for the wells it assumes for the average emissions, but the average US natural gas well produces about 127 mcfd. Therefore, the approximate emissions rate would be about 1.0 percent. Nor does EDF appear to distinguish sources of emissions in its fugitive discussion. For example, it does not discuss the share of emissions coming from equipment and those coming from storage tanks that have permitted releases. Since an LDAR program would not apply to these allowable emissions, the efficiency/cost estimates must be questioned.
>
> A second key point of the analysis relates to the value of natural gas where EDF assumes a price of $4.00/mcf. Producers have not received such a price for a long time and do not foresee such a price for many years. As the Independent Producers submitted in its original comments, the recent price for natural gas has been nearer $2.22/mcf of which the producer receives approximately $1.67/mcf. If this price replaces the EDF assumptions, the value of the recovered natural gas would drop from $1360 to $440 annually. Correspondingly, the cost effectiveness would change in the net case from $2.52/mcf to $5.48/mcf.
>
> A third point relates to the scope of fugitive leaks of the Leak Detection and Repair (LDAR) program. A study done by Carbon Limits (described below) concluded that fugitive leak emissions at well sites accounted for 17 percent of the total site emissions. Using this assessment of the 440 mcf/y of site emissions, only 75 mcf/y would be addressed by the LDAR program. And using the generous assumption of a 60 percent recovery, 45 mcf/y (0.12 mcfd) would be recovered. This would result in $75 in recovered value. The cost effectiveness would then become $44.58/mcf in the gross case and $42.91/mcf in the net case
>
> More critically, the issue of larger significance here is the application of an LDAR program to low production wells. These wells average about 24 mcfd rather than 127 mcfd. Moreover, in some significant natural gas producing states the average low production natural gas well is much less; in Pennsylvania, for example, it is 6.1 mcfd. Using the same ratio of emissions to production for the average national well would yield low production emissions rates of 0.24 mcfd nationally and 0.06 mcfd for Pennsylvania. On this basis the potential recovery would be 9 mcf/y for the national average low production well and 2.2 mcf/y for the Pennsylvania well. The gross and net cost effectiveness values would be $222.89/mcf and $221.22/mcf for the national wells and $911.81/mcf and $910.15/mcf for the Pennsylvania wells, respectively. Setting aside that most of the likely emissions would be from permitted storage tank vents, these assessments argue that the Optical Gas Imaging OGI LDAR approach is not cost effective.

For Carbon Limits, it stated:

> This report was prepared for the Clean Air Task Force by Carbon Limits. It is designed to assess LDAR programs using infrared cameras for various components of the natural gas value chain. Environmentalists like to reference it because of its general conclusions that these LDAR programs can be cost

effective. But, a closer look reveals a number of key points that demonstrate a very different result particularly in the context of low production wells.

First, like other analyses this report is based on recovering methane at a natural gas price of $4.00/mcf. While it does develop an effect case if natural gas were priced at $3.00/mcf, it does not approach an analysis at the $1.67/mcf prices that have characterized the recent prices that producers receive.

Second, as mentioned above, it concludes that natural gas well leaks that would be the subject of an LDAR program represent only 17 percent of the methane emissions from well sites.

Third, the report develops Net Present Value (NPV) determinations for each industry segment that it evaluates — well sites and well batteries, gas processing plants and compressor stations in gas transmission, and gas gathering systems. For well sites and well batteries, the Carbon Limits study concludes that infrared camera based LDAR programs are not cost effective at 85 percent of these sites — a percentage that exceeds the share of natural gas production facilities that are low production wells. Moreover, since this assessment is based on $4.00/mcf natural gas, it would thereby mean that such an LDAR program would be not be cost effective for an even greater percentage.

Consequently, even the material prepared by Keep It in the Ground environmentalists does not support the current LDAR program for low production wells.

A similar reality exists in EPA's analyses of its Subpart OOOOa Reconsideration LDAR requirements on low production wells. In its justification for removing the low production well exclusion it proposed in the Subpart OOOOa regulation, it concluded that it should base its analysis on component counts of equipment at facilities. IPAA does not agree with this approach. Moreover, when EPA used the component count basis for the Subpart OOOOa Reconsideration, it opened new questions about the viability of this approach. These questions range from the development of its low production component count in its model facility to the accuracy of its emissions factors to the calculation of cost effectiveness. These issues are discussed in detail in the Independent Producers 2018 Comments on pages 26 through 36. Following is a discussion that pulls together the key points:

c. EPA model plant calculations attribute 80 percent of low production natural gas wells to valves (63 percent) and thief hatches (18 percent) and 85 percent of low production oil wells to valves (38 percent) and thief hatches (48 percent). These calculations are based on questionable emissions factors.

Deconstructing the EPA's Model Low Production Well reveals that the primary factors in defining emissions are valves and thief hatches. This holds true for both natural gas and oil wells although valves are far more of a factor in the Model Low Production Well. The Independent Producers believe this calculation is highly questionable. As the Independent Producers have set forth above, both of the underlying assumptions on valves – the emissions factor and the number of valves – are not appropriately validated for the purpose of creating a costly regulatory program.

The valve emissions factor hinges on assumptions of the initial levels of emissions prior to the LDAR program and the recurrence of those emissions levels. Yet, the API analysis submitted to the EPA in February 2018 provides demonstrable data to produce an emissions factor approximately 25 percent of the factor the EPA used in its estimate.

Regarding the number of valves, the EPA's determination in its model facility that a low production wellsite includes 100 valves does not reflect all areas in the country that would be affected by these regulations, particularly as existing sources are affected in future regulatory actions.

i. <u>If these assumptions are incorrect, it significantly changes the cost-effectiveness assumptions of the EPA fugitive emissions program.</u>

Without addressing all of the assumptions in the EPA Model Low Production Well plant that are called into question by the additional information in the material that the Independent Producers acquired from the 13 states where we were able to get limited information, the information above on valves and the questionable emissions factor alone change the nature of the EPA's cost-effectiveness analysis.

For example, if the number of valves used for the natural gas Model Low Production Well plant is changed to 20 and the API emissions factor for valves is used to calculate the fugitive emissions program's cost-effectiveness using the EPA spreadsheet provided in the Docket[15], cost per ton of recovered methane increases by a factor of about 2.5. More tellingly, the amount of recovered methane would be estimated at 0.092 mcfd. It is hard to imagine that this miniscule amount of methane would even be detectable; it is unlikely to even be measurable as additional product.

Moreover, these calculations do not address the cost of the EPA proposed program. As we have shown earlier, past history with OGI programs has demonstrated these programs to have been far costlier than the EPA presumed. To put an additional point on it, for the Pennsylvania wells that were identified in this inventory, the operator estimates that the cost of the biennial EPA OGI fugitive emissions program would exceed $800,000 – or $400,000 per year. The average production of those wells is about 6 mcfd.

[15] Proposed_Rule_OOOOa_TSD_Section_2_-_OGI_Compressor_Model_Plant_Costs

d. Assessing the cost impact on low production wells needs to look beyond the common tests of cost effectiveness in a cost per ton of reduced emissions to address the cost impact in the profitability of these small wells.

In the context of low production wells, the EPA's analysis of the cost effectiveness of its regulations, as flawed as it may be, also fails – like most cost-effectiveness analyses to address a more critical issue. Cost-effectiveness analyses typically look at the cost per unit of pollutant recovered. For low production wells, wells generally operated by small businesses, there is a remaining significant issue – whether the absolute cost can be absorbed by the operations that are regularly economically challenged.

Not surprisingly, the impact of a fugitive emissions program is significantly different between small and large wells. For the past several years, the EDF has polluted the air with an analysis that it developed showing that a variety of methane controls are cost effective when that is not the case. The EDF states these controls only cost a few cents.

The problem is that the EDF's analysis is flawed and, when the average low producing well produces 22 mcf per day, a few cents per mcf is highly significant. Moreover, the economic assumptions can be as significant as the emissions assumptions. In the Reconsideration Rulemaking, the EPA indicates that it uses a natural gas value of $3.42/mcf. This amount may reflect current natural gas prices at a time where storage limitations and high demand have driven prices higher. However, it fails to reflect that prices in the past several years have been well below this level. In fact, in the past two years, national natural gas prices have triggered the Marginal Well Tax Credit with the Internal Revenue Service calculating that the average price in 2016 was $2.38/mcf and in 2017 was $2.17/mcf. Moreover, producers do not receive the full value of the sales price; they must pay royalties and taxes that reduce the amount received by about 25 percent. Using the IRS average value for those two years ($2.22/mcf), the producer would then receive about $1.67/mcf for any recovered gas.

The EPA's Model Low Production Well analysis calculates that about 280 mcf/yr are emitted and 30 percent is recovered by its LDAR program – 84 mcf/yr. We believe this determination is too high, that API's emission factor is more accurate. Using the high valve count that the EPA assumes for its model well and the API emissions factor yields a recovery amount of 44 mcf/yr. It should be noted that this amount is about 0.12 mcfd and one has to raise a question of whether this amount can even be found or will show up in the daily production measurements.

> Using the more realistic product prices, this presumed recovery adds about $73.50 to the annual income of the Model Low Production Well or about $36.75 to the income of a well. It is noteworthy to point out that even this small recovery may overstate the amount since it is highly dependent on the number of valves at a facility.
>
> The larger question is what impact does this have on a low producing well. Using the cost information above, the average low producing well (22 mcfd) would receive daily income of $36.75 ($13,400 per year).
>
> It is difficult to determine operating costs but the EIA released a report in March 2016, *Trends in U.S. Oil and Natural Gas Upstream Costs*, which assessed a wide range of costs and looked at several production areas. One of its evaluations addressed operating costs in the Marcellus play – the world-scale natural gas play in the northeastern states. The report estimated that Marcellus operating costs range from $12.36/BOE to $29.60/BOE. Using the standard 1 BOE = 6 mcf conversion, it produces operating costs ranging from $2.06/mcf to $4.93/mcf. Applying these costs to the average low producing well results in a daily cost range of $45.32 to $108.46.
>
> Consequently, the average low producing well would have to have a natural gas price in the range of $2.06/mcf to $4.93/mcf to break even. In Pennsylvania, where the average low production natural gas well produces closer to 6.0 mcfd and the typical wellsite is one well rather than two, the challenge is even greater. Income would be about $10.00/day with operating costs in the range of $12.00 to $29.00 daily. In this difficult financial situation, the application of the EPA LDAR program is a far more significant factor than the EPA has presumed in its analysis, given that the amount is essentially unmeasurable.
>
> Clearly, there are many factors that come into play in this analysis – price of natural gas, cost of the LDAR program, operating costs. The fundamental point is that an LDAR program that *may* be justified for large producing wells will have a very different impact on small ones. The EPA should develop a methodology that reflects these differences and it has not.

Moreover, in a different regulatory context, EPA has demonstrated that its assessment of LDAR regulation on existing low production wells does need more consideration. Subpart OOOOa is not the only EPA regulatory action where the issue of developing LDAR requirements has been addressed. In October 2016, EPA released its CTG for existing oil and natural gas production facilities in ozone nonattainment areas. This CTG includes a model regulation for LDAR. Significantly, it does not recommend the Subpart OOOOa type of LDAR for low production existing wells.

As we have observed previously, when EPA developed its cost effectiveness assessments for its LDAR requirements in Subpart OOOOa, those requirements did not apply to low production wells. Consequently, those implications have never been fully vetted. EPA's action in its CTG reflects the reality that it did not know how substantial those impacts would be. As we have described, our assessments conclude that they would be broad and significant, likely catastrophic, for the 750,000 low production wells across the U.S.

When EPA develops its Section 111(d) emissions guidelines, it must approach its effort with a full understanding of the scope and complexity of the nation’s oil and natural gas production industry. Past Section 111(d) emissions guidelines have subcategorized facilities to reflect such differences and any that are developed for the oil and natural gas production industry should follow the same approach.

E. EPA has never collected any significant data to identify the emissions profile of low production wells. Only the Department of Energy (DOE) has initiated a study of emissions from low production wells. Information from the effort should be utilized.

A critical shortcoming of the development of regulations affecting oil and natural gas production facilities under Subpart OOOO, Subpart OOOOa and the CTG is the lack of information to establish accurate emissions profiles.

For Subpart OOOO, EPA largely turned what had been technologies that had been used in the Natural Gas STAR voluntary program. Consequently, it did not develop new or robust data establishing emissions profiles of production operations. It largely relied on studies that had been done in the mid-1990s that were never intended for regulatory purposes. While the general information in these materials point directionally to the level of emissions from production operations, they do not reflect the complexities of the industry nor were they intended to. In particular, to the degree that they represent low production operations, it would be incidental to the study and insufficient to serve as a basis for a regulatory program. However, since the Subpart OOOO regulations were structured around widely used technologies, the inadequacies of the emissions profiles were generally not crucial. They did, however, result in issues when voluntary technologies voluntary became required and where those technologies were not applicable in specific instances such as the use of nitrogen for fracturing rather than water.

For Subpart OOOOa, the limitations of accurate data became clear. When EPA created its LDAR requirements, it created from whole cloth a set of specifications that were used nowhere else and concluded that they were "adequately demonstrated" for the purposes of Section 111. As API demonstrated, these reports were inadequate for the purposes of accurately estimating emissions reductions. For low production wells, they were wholly inappropriate.

In the Subpart OOOOa Reconsideration, EPA attempts to expand the basis for predicting emissions from low production wells relying on limited work in the Barnett Shale. The Independent Producers addressed this approach in its 2018 Comments:

> The EPA's reliance on approximately 25 potentially low production wells in one play— the Barnett Shale in Texas — to define its Model Low Production Well is inadequate. This action is flawed for several reasons. First, there is no reason to believe that the Barnett Shale is representative of all low production wells in various plays across the country. Second, the data that was collected in the Fort

> Worth Study was not intended to address low production wells specifically and is simply a subset of wells incidental to a larger study. Third, even this well selection appears flawed; some wells do not appear to be low production wells. Fourth, and perhaps most importantly, trying to establish a Model Low Production Well on the basis of 25 single basin wells will lead to ineffective results and unproductive, inefficient use of resources

A more detailed discussion addresses specific concerns:

> The EPA relies heavily on data from a study in Fort Worth, Texas, on wells in the Barnett Shale formation. Unlike most studies, this one was conducted with the cooperation of natural gas producers and included facility information. While the emissions data was taken by offsite mobile sampling for short time periods like the other emissions data referenced in the EDF studies, detailed production site information was provided. The EPA relies on this information to develop its Model Low Production Well. However, like all other studies, the Fort Worth study collected data broadly, capturing both low production wells and large wells. Low production wells were not specifically targeted or defined at the time of the data collection.
>
> The EPA has now apparently extracted from the larger data base those wells with production at or below its 90 mcfd low production well threshold. It includes 25 dry gas wells and two wet gas wells. However, a closer examination of this data demonstrates key flaws. These flaws are important because the selected wells then shape the model facility. The model facility then becomes the basis for the low production well emissions estimates that then justify the requirements for the fugitive emissions program.
>
> For example, of the 25 dry gas wells, eleven wells show no production at the time that the emissions data was taken. The consequence of including the wells with zero or less than one mcfd is the impact on the number of pieces of equipment at a site that then becomes the basis of the model facility and the basis for emissions estimates from these wells. For example, the number of valves at a site drives valve emissions which are a significant factor in the total low production model facility emissions calculations. With all 25 sites in the calculation, the EPA generates an average valve number of 108. However, if the zero and less than one mcfd wells are removed, the average valve number drops to 75. Similarly, the number of tanks per well site drops from two to one.
>
> Better information on the nature of low production well sites is needed to assess an appropriate model well facility if a model facility is even appropriate given the diversity of production across basins.

Using these highly questionable analyses to develop existing source regulations that could be driven by Section 111(d) impose a severe threat to the 750,000 low production wells throughout the nation. Moreover, DOE has initiated a study to specifically address the emission profiles of low production wells. The study was announced in 2018 and activity to gather and assess information is underway. The DOE effort has been constrained by the COVID crisis, but work is underway and information is available. Hopefully, the project will be completed in 2021, but, even if it is not, significant information could inform the Section 111(d) process.

Conclusion

IPAA appreciates the opportunity to provide substantive information to EPA through this open docket. EPA will need to assure that it fully addresses the complexity of the oil and natural gas production industry as it develops potential revisions to Subpart OOOOa and Section 111(d) emissions guidelines for methane emissions. Unfortunately, the political rhetoric surrounding these issues distorts the actual nature of their magnitude and the options to effectively address them. EPA's challenge will be to subordinate these allegations to the valid information that must be developed and used in this effort.

Sincerely,

Daniel T. Naatz
Executive Vice President

APPENDIX A

December 4, 2015

Gina McCarthy
Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Ave., NW
Washington, D.C. 20460

VIA ELECTRONIC MAIL

Re: Comments for Three Regulatory Proposals issued September 18, 2015:

1) **Oil and Natural Gas Sector: Emission Standards for New and Modified Sources (80 Fed. Reg. 56,593)**

2) **Release of Draft Control Technique Guidelines for the Oil and Natural Gas Industry (80 Fed. Reg. 56,577)**

3) **Source Determination for Certain Emission Units in the Oil and Natural Gas Sector (80 Fed. Reg. 56,579)**

Dear Administrator McCarthy:

These comments are filed on behalf of the Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC) (collectively, IPAA/AXPC).[1]

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 most directly be impacted by the U.S. Environmental Protection Agency (EPA) policy decisions to regulate methane directly from the oil and natural gas sector. Independent producers develop about 95 percent of American oil and gas wells, produce 54 percent of American oil, and produce 85 percent of American natural gas. Historically, independent producers have invested over 150 percent of their cash flow back into domestic oil and natural gas development to find and produce more American energy. IPAA is dedicated to ensuring a strong, viable domestic oil and natural gas industry, recognizing that an adequate and secure supply of energy is essential to the national economy.

AXPC is a national trade association representing 30 of America's largest and most active independent oil and natural gas exploration and production companies. AXPC members are "independent" in that their operations are limited to exploration for and production of oil and natural gas. Moreover, our members operate autonomously, unlike their fully integrated counterparts, which operate in additional segments of the energy business, such as downstream refining and marketing. AXPC members are leaders in developing and applying innovative and

[1] For ease of reference, these comments include an Acronym Index, attached hereto as "Attachment A."

advanced technologies necessary to explore for and produce oil and natural gas, both offshore and onshore, from unconventional sources.

Additionally, they are joined by the American Association of Professional Landmen (AAPL), the Association of Energy Service Companies (AESC), the International Association of Drilling Contractors (IADC), the International Association of Geophysical Contractors (IAGC), the National Stripper Well Association (NSWA), the Petroleum Equipment & Services Association (PESA), the US Oil & Gas Association (USOGA), and the following organizations:

Arkansas Independent Producers and Royalty Owners Association
California Independent Petroleum Association
Coalbed Methane Association of Alabama
Colorado Oil & Gas Association
East Texas Producers & Royalty Owners Association
Eastern Kansas Oil & Gas Association
Florida Independent Petroleum Association
Idaho Petroleum Council
Illinois Oil & Gas Association
Independent Oil & Gas Association of New York
Independent Oil & Gas Association of West Virginia
Independent Oil Producers’ Agency
Independent Oil Producers Association Tri-State
Independent Petroleum Association of New Mexico
Indiana Oil & Gas Association
Kansas Independent Oil & Gas Association
Kentucky Oil & Gas Association
Louisiana Oil & Gas Association
Michigan Oil & Gas Association
Mississippi Independent Producers & Royalty Association
Montana Petroleum Association
National Association of Royalty Owners
Nebraska Independent Oil & Gas Association
New Mexico Oil & Gas Association
New York State Oil Producers Association
North Dakota Petroleum Council
Northern Montana Oil and Gas Association
Ohio Oil & Gas Association
Oklahoma Independent Petroleum Association
Panhandle Producers & Royalty Owners Association
Pennsylvania Independent Oil & Gas Association
Permian Basin Petroleum Association
Petroleum Association of Wyoming
Southeastern Ohio Oil & Gas Association
Tennessee Oil & Gas Association
Texas Alliance of Energy Producers

Texas Oil and Gas Association
Texas Independent Producers and Royalty Owners Association
Utah Petroleum Association
Virginia Oil and Gas Association
West Slope Colorado Oil & Gas Association
West Virginia Oil and Natural Gas Association

Collectively, these groups represent 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 most significantly affected by the actions resulting from these regulatory proposals. In addition to the specific comments made herein, we support those comments submitted separately by the participants in these comments. IPAA/AXPC also endorses and supports the comments of the Western Energy Alliance (WEA) and the American Petroleum Institute (API) submitted on the proposed rules referenced above.

As an initial matter, these comments are designed to address the three aforementioned proposed regulatory actions simultaneously and will be submitted to all three dockets as all three proposals target the oil and natural gas industry, and certain responses and arguments from IPAA/AXPC are applicable to all of the proposals. Additionally, comments on all three proposals were initially due November 17, 2015. IPAA requested an extension of the 60-day comment period on October 2, 2015, due to the complexity and breadth of the proposed regulations and that certain key supporting documents were not available in the docket for public review when the EPA published the proposals in the Federal Register on September 18, 2015. In late October/early November various informed parties who had requested additional time to comment learned that they would have until December 4, 2015. On November 13, 2015, the extension was published in the Federal Register.

EXECUTIVE SUMMARY

These comments raise a number of key issues associated with EPA's proposals for Clean Air Act (CAA or Act) New Source Performance Standards (NSPS), Control Technique Guidelines (CTG) and Source Determination for oil and natural gas production facilities.

EPA justifies its proposals in the context of the Administration's Climate Action Plan with a specific target of reducing methane emissions from the oil and natural gas sectors by 40-45 percent during the time period from 2012 through 2025. However, as these comments demonstrate, EPA's proposals are unnecessary, unjustified, poorly developed and counterproductive.

First, the Administration proclaims its intent to reduce methane emissions by 40-45 percent from the oil and natural gas sectors. At the same time, it takes credit for its 2012 volatile organic chemical/methane emissions regulations in these sectors that exceed its own target. Moreover, it fails to recognize that much of the reduction it seeks has occurred since 2012 from voluntary industry actions. The oil and natural gas production sector is 1.07 percent of the national Greenhouse Gas Inventory and its methane emissions will continue to drop because of industry emissions management. Consequently, any justification for additional regulation must be thoroughly weighed based on cost effectiveness and economic consequences. EPA's proposals fail these tests.

Second, within the NSPS proposal, the most egregious element is the proposed fugitive emissions regulations that are based on purely speculative emissions reductions but, as designed, are excessively and unnecessarily burdensome. Oil and natural gas production fugitive emissions management is an emerging arena with companies and state regulatory programs still learning how best to efficiently and effectively control them. Several states are currently implementing programs; none of which parallel EPA's proposals. Experience with those state efforts demonstrates that emissions patterns result from a few high emissions sources that can be managed quickly with sustained reductions. EPA's proposal to lock in an unworkable program for at least 5 years is arbitrary and inappropriate. EPA should await the analysis of state programs to determine whether an NSPS is logical or necessary.

Third, EPA also proposed a volatile organic compound (VOC) CTG for Ozone nonattainment areas. This proposal fails to comply with the Agency's fundamental responsibility of developing Reasonably Available Control Technology (RACT). Instead, EPA largely transposes the same requirements in the 2012 NSPS and those proposed in this regulatory action from new sources to existing ones. In doing so, EPA fails to determine whether these new facility requirements are economically appropriate as CTG for existing sources on a national basis.

Fourth, by linking its CTG proposal to its Climate Action Plan, EPA fails to address the need for the CTG with regard to Ozone nonattainment. Yet, the threshold question for these regulations is whether they are necessary and appropriate for attainment of the Ozone National Ambient Air Quality Standards (NAAQS). If fact, based on EPA's analysis of the regulatory framework to attain the recently revised Ozone NAAQS, EPA demonstrates the CTG are wholly unnecessary. Prior to proposing these CTG, EPA concluded that all but a few areas of the country will meet the new Ozone NAAQS by 2025 using national, federal regulatory requirements. Consequently, for these areas, the proposed CTG are excessive regulations. For the remaining enduring Ozone nonattainment areas, if there are oil and natural gas production operations that need to be addressed, they can be managed through local determinations of Reasonably Available Control Measures (RACM) and do not require CTG.

Fifth, because these CTG are unnecessary, their likely impact will be the inappropriate restriction of economic growth in Ozone nonattainment areas. Given that EPA has concluded that Ozone NAAQS attainment will be achieved without these CTG, these CTG will remove emissions that could be used as CAA required new source offsets. Therefore, they would unnecessarily impede economic growth that would otherwise occur.

Sixth, in its proposal to address Source Determination for oil and natural gas production facilities, EPA should recognize that new facilities should be based on a narrow definition that hones closely to the approach EPA has used under the National Emissions Standards for Hazardous Air Pollutants (NESHAP) program. Where there are issues regarding scope, the source determination should be based on the sites being contiguous in addition to sharing the same Standard Industrial Classification (SIC) Code and being under common control.

These comments will expand on the issues raised above and other more specific ones. Ultimately, however, IPAA/AXPC argues that EPA's NSPS and CTG proposals must be withdrawn, reconsidered and revised to be consistent with the Administration's own Climate Action Plan objectives and its assessment of the capability of the nation to meet the revised Ozone NAAQS. To do otherwise would arbitrarily impose excessive regulation on the oil and natural gas setoff for no purpose other than to expand the already burdensome federal regulatory program.

I. EPA's Additional New Source Performance Standards for the Exploration and Production Segment and Control Technique Guidelines for Existing Sources are Unnecessary and Misplaced.

EPA's proposed NSPS targeting methane emissions from the exploration and production segment of the oil and natural gas sector are unnecessary, unwarranted, and wasteful – not only to those subject to the regulations but to the state and federal regulators who must implement the rules if EPA does not change its course. Similarly, proposing essentially the same set of controls on existing sources in nonattainment areas (and ozone transport regions) using the proposed CTG with no additional economic justification/cost-benefit analysis is one more indication that EPA is rushing to judgment with its latest salvo of regulations. In April 2014, EPA acknowledged the lack of knowledge to regulate a variety of sources and implemented a White Paper process that sought additional technical information on a variety of sources.[2] Industry raised numerous concerns regarding EPA's lack of data regarding emissions from these sources and the cost/effectiveness of controls from these sources. Nonetheless, EPA proceeded headlong to promulgate its methane NSPS – relying heavily on the Regulatory Impact Analysis (RIA) from the VOC NSPS promulgated in 2012. The methane regulations need to "stand on their own" and be justified on their own, not simply as an "add-on" to the VOC NSPS.

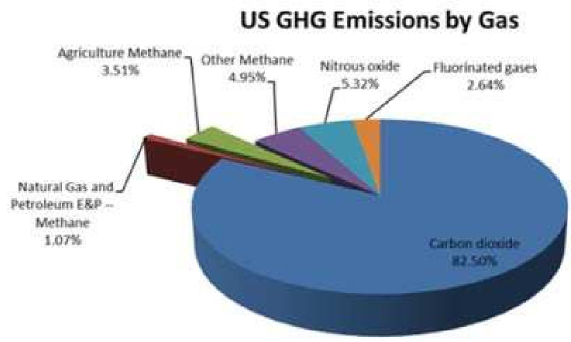
These regulations will have a serious negative economic impact on American oil and natural gas production while providing marginal environmental benefit beyond the regulations EPA promulgated in 2012 to regulate VOCs from essentially the same set of production and exploration emission sources.[3] To understand the full impact, it is essential to put the entire issue in perspective.

---

[2] U.S. Environmental Protection Agency, Section on Oil and Natural Gas Air Pollution Standards, *Methane*, *available at* http://www3.epa.gov/airquality/oilandgas/methane.html.

[3] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 77 Fed. Reg. 49,490 (Aug. 16, 2012).

From 2008 through 2013, U.S. shale gas production grew 400 percent,[4] while methane emissions have declined 13.3 percent. According to 2013 EPA Greenhouse Gas (GHG) Reporting data, methane emissions from oil and natural gas exploration and production are 1.07 percent of total U.S. GHG emissions. Further reductions will occur because of "green" or "reduced emission completions" that are being phased-in through the 2012 regulations.[5] According to EPA's latest GHG Reporting Program: "[In 2013] reported methane emissions from petroleum and natural gas systems sector have decreased by 12 percent since 2011, with the largest reductions coming from hydraulically fractured natural gas wells, which have decreased by 73 percent during that period. EPA expects to see further emission reductions as the agency's 2012 standards for the oil and gas industry become fully implemented."[6] These reductions are remarkable, given that a major component of the 2012 standards, the reduced emission completion requirements, only became effective January 1, 2015.



In January 2015, the Administration announced its intent to initiate rulemaking to further reduce methane emissions from oil and natural gas systems, including the production sector.[7] Specifically, it announced a target of a 40-45 percent reduction in 2012 emissions by 2025. For the production and exploration segment of the oil and natural gas sector, additional regulations are unnecessary. As the Administration observed in its announcement:

> In 2012, the Environmental Protection Agency (EPA) laid a foundation for further action when it issued standards for volatile organic compounds (VOC) from the oil and natural gas industry. These standards, when fully implemented, are expected to reduce 190,000 to 290,000 tons of VOC and decrease methane

[4] U.S. Energy Information Administration, *available at* http://www.eia.gov/dnav/ng/hist/res_epg0_r5302_nus_bcfa.htm.

[5] In 2012, EPA finalized a Clean Air Act (CAA or Act) Section 111(b) NSPS targeting VOCs emissions from hydraulically fractured natural gas wells. This rulemaking also reduces methane emissions as co-benefit. Methane and VOCs are emitted from oil and natural gas production facilities at the same time from the same equipment. Consequently, reducing one also reduces the other. The effects of the 2012 NSPS are still unfolding.

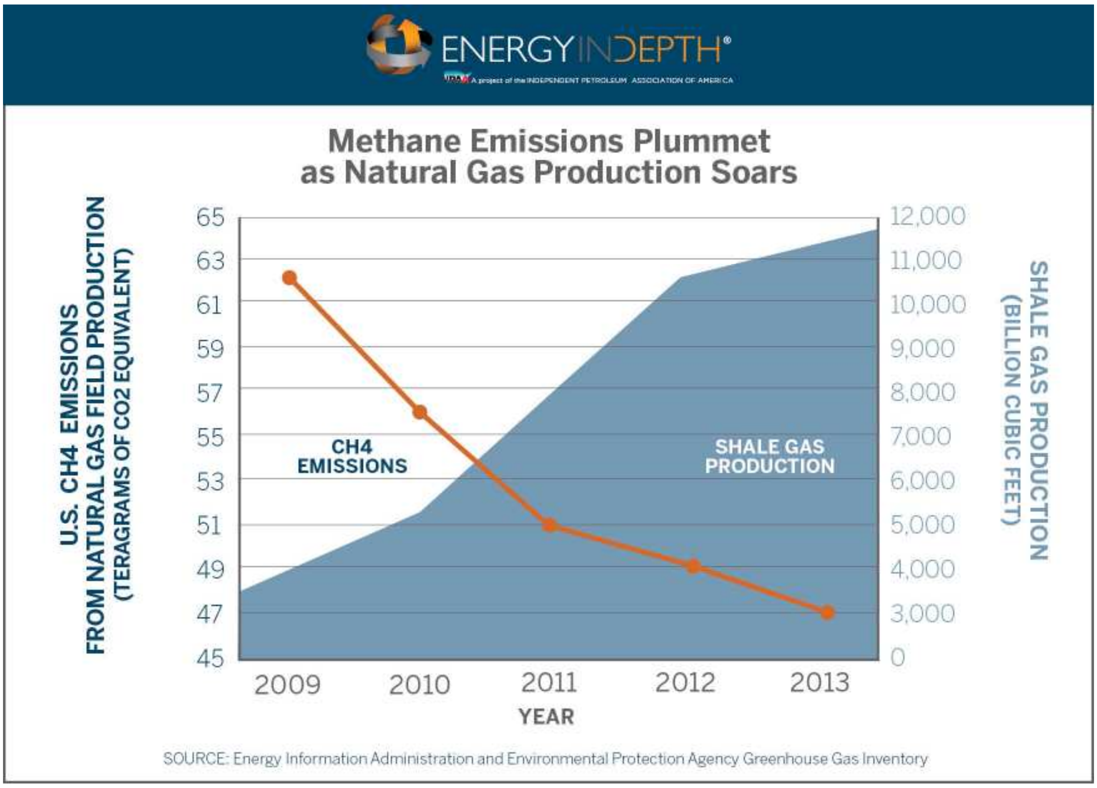
[6] Requirements for reduced emission completions on natural gas wells were promulgated in August 2012 but did not become effective until January 1, 2015. Oil and Natural Gas Sector: Reconsideration of Additional Provisions of New Source Performance Standards, 79 Fed. Reg. 79,018 (Dec. 31, 2014) (codified at 40 C.F.R. pt. 60).

[7] Press Release, The White House, Fact Sheet: Administration Takes Steps Forward on Climate Action Plan by Announcing Actions to Cut Methane Emissions (Jan. 14, 2015), *available at* https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

> emissions in an amount equivalent to 33 million tons of carbon pollution per year.[8]

Over 99 percent of the EPA projected reductions occur from the exploration and production sector. In 2013, exploration and production emissions of methane were 71 million tons of CO_2 equivalent. Consequently, by EPA's own numbers, the 2012 NSPS regulations will reduce emissions by 46 percent. This reduction exceeds the emissions target percentage of the production sector of the oil and natural gas industry.

EPA attempts to argue that its regulations are needed because methane emissions "are projected to increase by about 25 percent over the next decade if additional steps are not taken to reduce emissions from this rapidly growing industry."[9] Yet, this statement is wholly inconsistent with the experience over the past several years in the exploration and production sector of the industry. This segment has demonstrated that growth in production not only provides more clean-burning, GHG-reducing product, it has been done while reducing methane emissions as the following graphic shows:



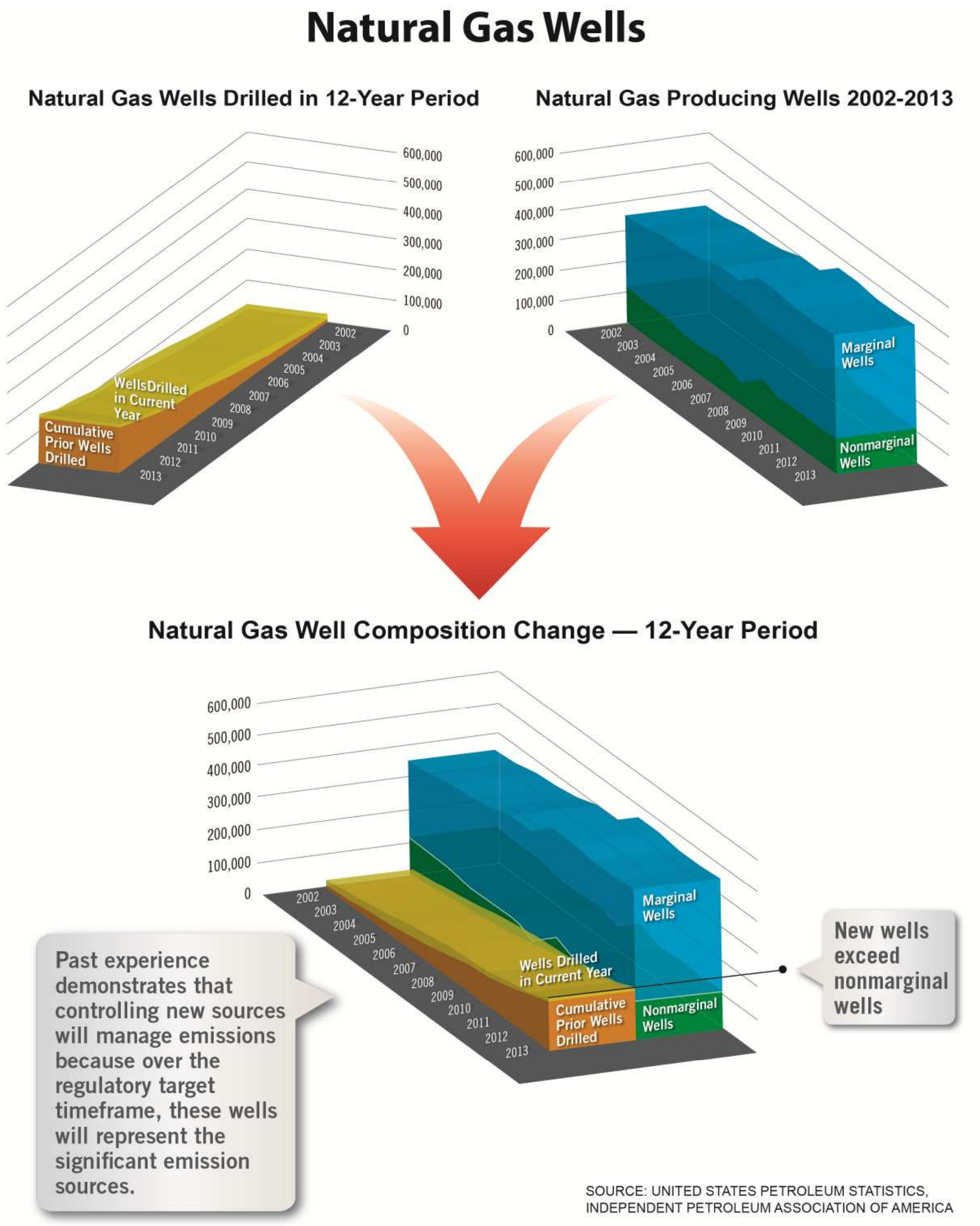
[8] *Id.*

[9] U.S. Environmental Protection Agency, Fact Sheet: EPA's Strategy for Reducing Methane and Ozone-Forming Pollution from the Oil and Natural Gas Industry (Jan. 14, 2015), *available at* https://www.whitehouse.gov/the-press-office/2015/01/14/fact-sheet-administration-takes-steps-forward-climate-action-plan-anno-1.

Significantly, these reductions in methane emissions have occurred prior to full implementation of the 2012 NSPS.

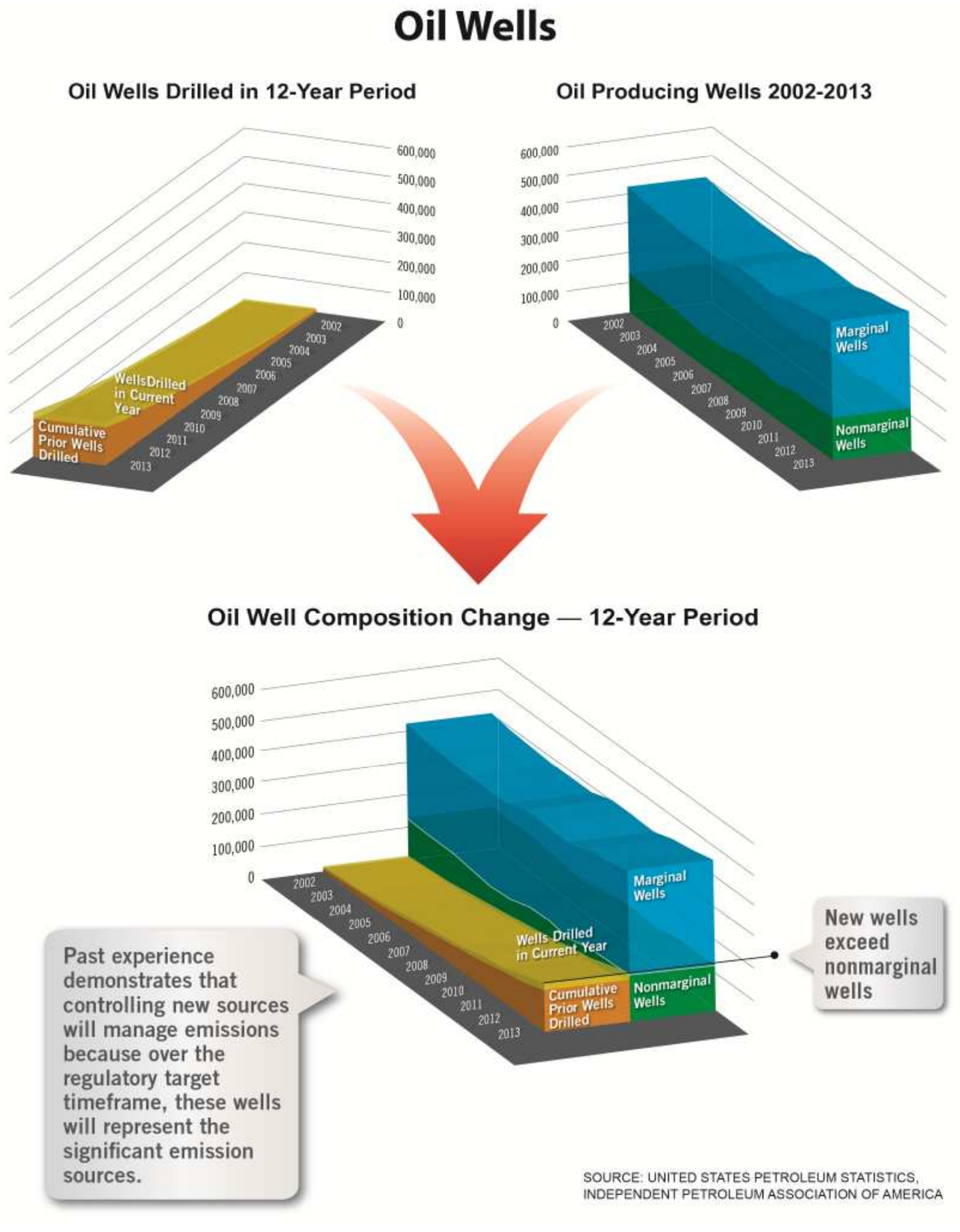
Moreover, because of the nature of oil and natural gas production, the application of controls on new sources will achieve the Administration's objectives without the need to create extensive existing source regulations. Oil and natural gas production operations differ from other types of manufacturing. After the period of initial production, wells begin to decline – generally referred to as the "production decline curve." And as the production of the well declines, its ability to emit VOCs and methane into the atmosphere also declines. Emissions from these older wells will be a smaller portion of the 1.07 percent of emissions, yet EPA's decision to regulate methane directly under Section 111(b) of the CAA and proposed CTG subjects tens of thousands of existing wells to regulation. IPAA/AXPC questions the cost-effectiveness of the proposed requirements to existing sources. The regulatory burden on state and federal regulators of exposing hundreds of thousands of existing sources is completely overlooked in EPA's proposal.

The declining nature of oil and natural gas wells also differentiates the exploration and production segment of the oil and natural gas sector from other segments further downstream where emissions remain fairly constant overtime. Ultimately, the production from the "new" wells declines to the point where they become "marginal" wells. These are defined as wells that produce 15 barrels/day of oil or less and 90 mscf/d or less of natural gas. Currently, there are over 1.1 million oil and natural gas wells in the United States; approximately 760,000 are marginal wells. However, these small individual wells account for about 20 percent of U.S. oil production and 13 percent of its natural gas production. Consequently, unlike manufacturing facilities where new facilities do not replace existing ones, in the oil and natural gas production industry, the implementation of technology on new wells will rapidly result in its application across the breadth of the industry as new wells become the predominant source of emissions for the industry. This can be understood by looking at past experience as shown in the graphs below:



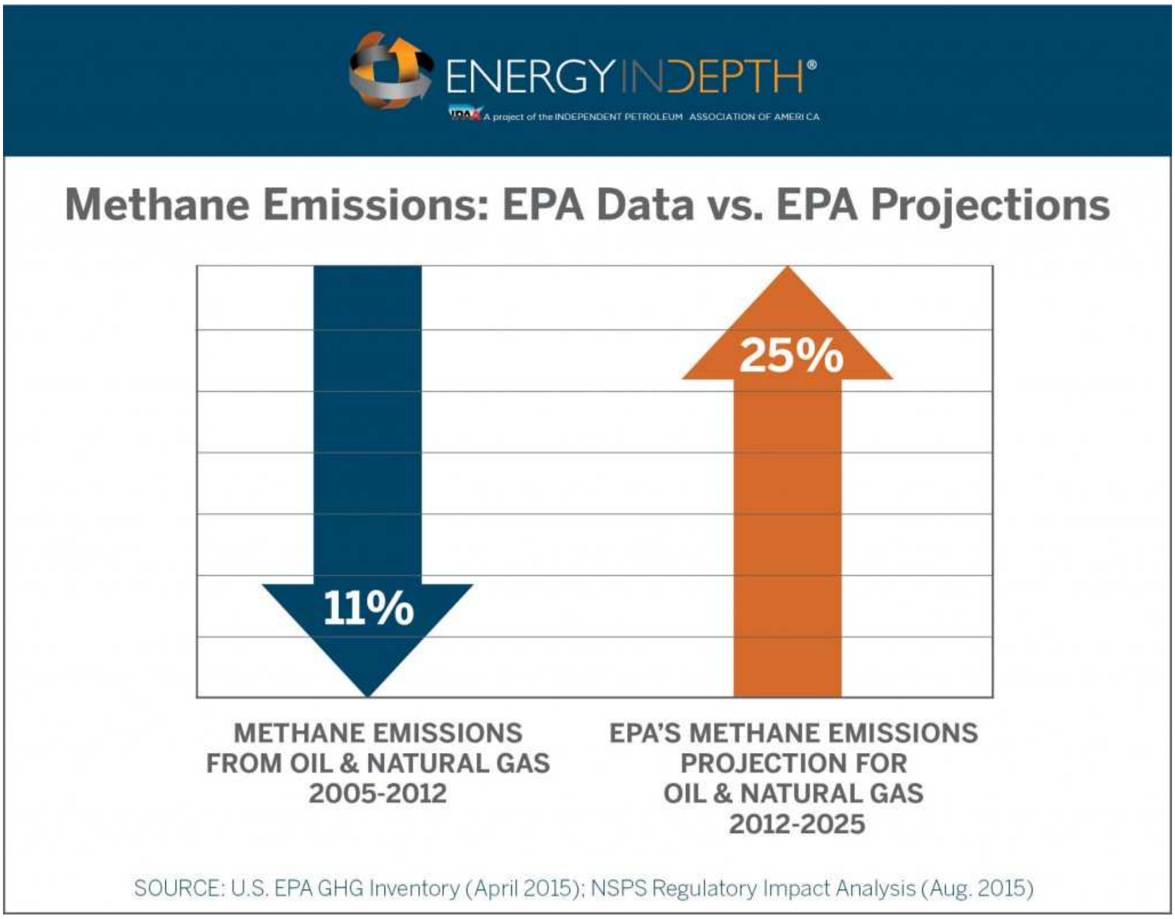
As this graphic demonstrates, after 12 years wells subject to the new source regulatory requirements will dominate the production of natural gas, and the remaining wells will be marginal wells with minimal incremental emissions beyond the emissions from sources already subject to regulation. The cost associated with reducing those incremental emissions will be greater than the cost of implementing controls on new or modified sources and will likely make many of the marginal wells uneconomic, causing them to be shut in/abandoned. The opportunity cost or value of that last production is not offset by the minimal emissions reductions achieved by regulating existing sources.

A similar pattern exists for oil wells as shown below:



While this analysis is based on past experience, if it were expanded to a 20-year period, it would show a similar trend and demonstrate that the use of new source regulations are more than adequate to address the Administration's interest in reducing methane emissions from the oil and natural gas sector, in general, and the exploration and production segment, in particular. EPA has failed to adequately account for and justify subjecting existing exploration and production sources to regulation under Section 111 of the CAA or through the CTG.

As Energy In Depth (a research, education, and public outreach campaign supported by IPAA) recently reported, EPA's assumptions regarding methane emissions from the oil and natural gas industry are not supported by EPA's own data.

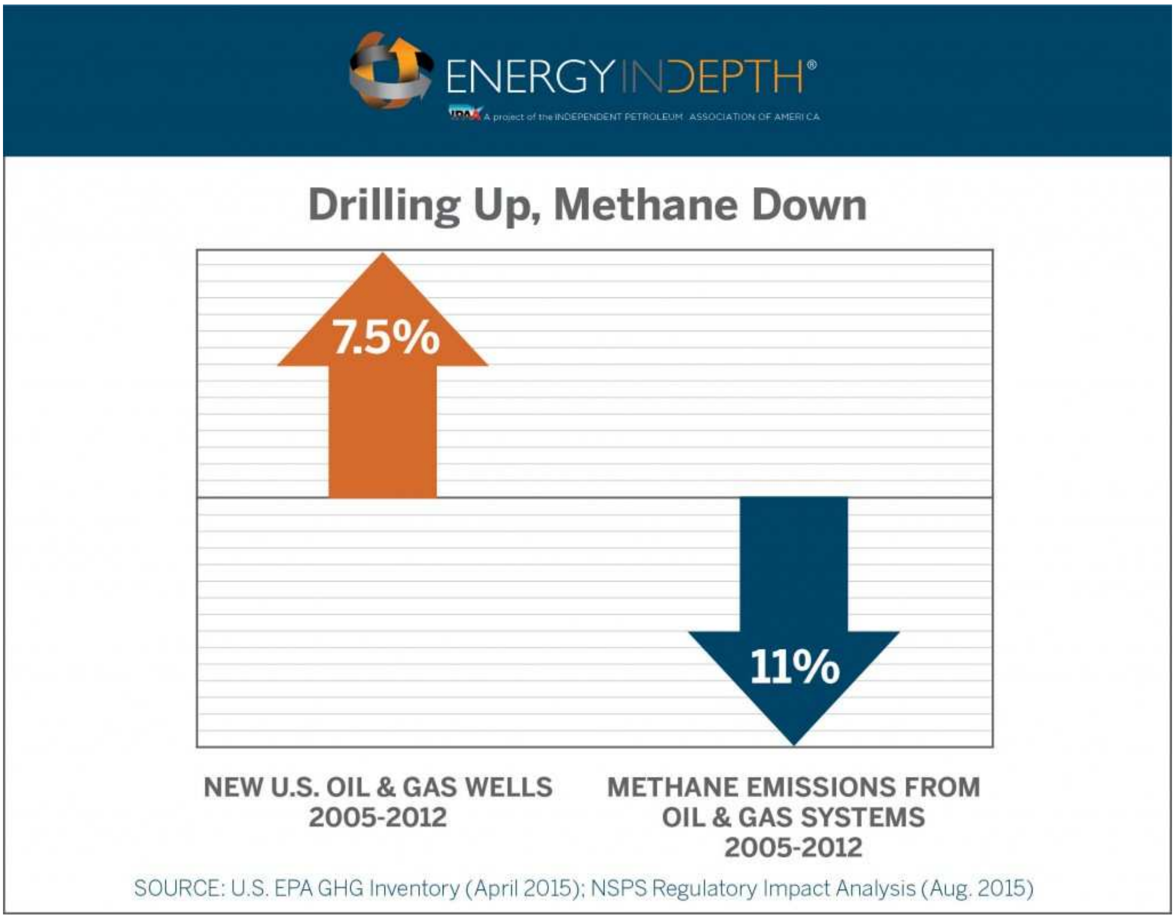


More specifically, Energy In Depth found:

- EPA projects methane emissions from the oil and natural gas sector will increase over the next decade, but **methane emissions from that sector have declined by more than 22 million metric tons** since 2005.
- Over the past decade, the United States added more than 86,000 new wells, during which **methane emissions from petroleum and natural gas systems fell by 11 percent**.
- EPA's flawed assumptions on methane emissions raise questions about the agency's cost-benefit calculation, and EPA could be **underestimating engineering costs by more than $10 million**.

- The EPA could also be **overstating the climate benefits of the rule**, since methane emissions may be significantly lower than EPA's projections.[10]

As discussed below, EPA's economic justification for it proposed regulations is problematic. But even the past does not support EPA's fundamental assumption that more drilling means more emissions:



EPA has projected that an increase in oil and natural gas activity will result in a 25 percent increase in methane emissions. But since 2005, methane emissions from U.S. oil and natural gas systems have fallen by a greater percentage than the number of new wells drilled.

IPAA/AXPC has repeatedly told EPA that additional regulation is not needed. Market forces drive the industry to minimize emissions. Unlike certain "products" in other industries with "emissions" that are a by-product or negative externality associated with the production, the "emission" of concern to EPA is the very product this industry brings to the market.

---

[10] Steve Everley, *New EPA Methane Regulations Based on Flawed Emissions Assumptions* (2015), Energy in Depth, *available at* http://energyindepth.org/national/epa-methane-regulations-flawed-emissions-assumptions/. IPAA/AXPC incorporate by reference the entire Energy In Depth article as part of its comments.

II. The Industry's Recent Past is Not Its Prologue – Therefore EPA's Proposed Regulations are Not Justified

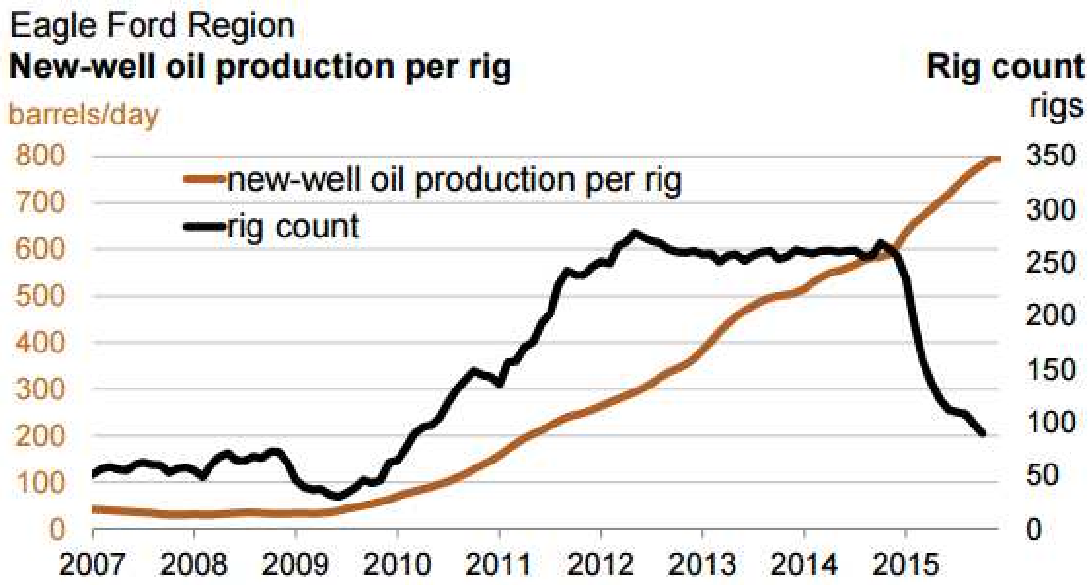
EPA justifies its proposed regulations in large part on the last 10 years of growth in the American oil and natural gas industry – perhaps the most dynamic and rapid growth period in the history of the industry:

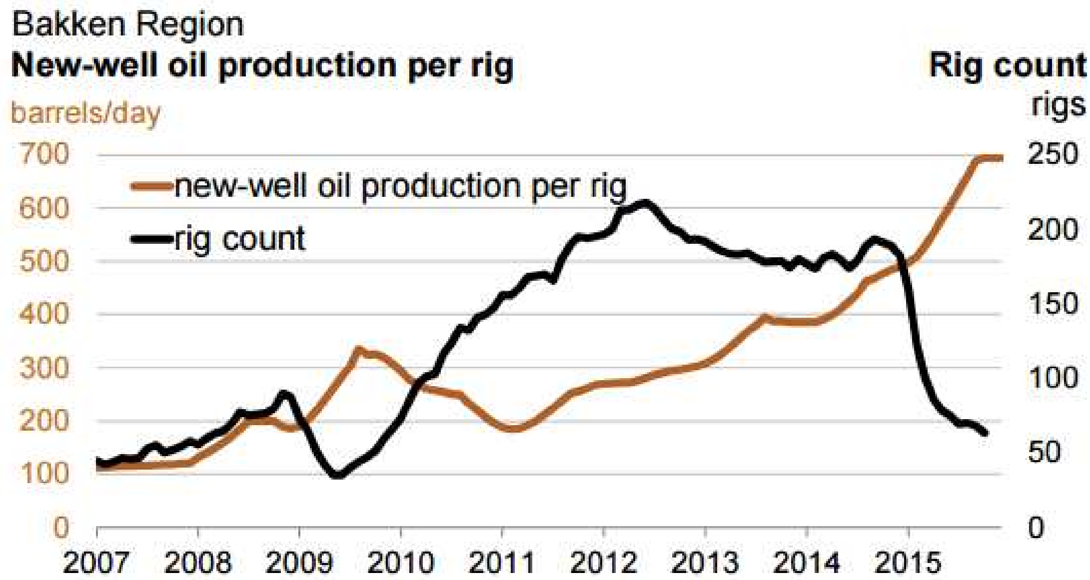
> The EPA has projected affected facilities using a combination of historical data from the U.S. GHG Inventory, and projected activity levels, taken from the Energy Information Administration (EIA's) Annual Energy Outlook (AEO). The EPA derived typical counts for new compressors, pneumatic controllers, and pneumatic pumps by averaging the year-to-year increases over the past ten years in the Inventory. New and modified hydraulically fractured oil well completions and well sites are based on projections and growth rates consistent with the drilling activity in the 2014 Annual Energy Outlook."[11]

As much as the oil and natural gas sector would like to see that growth rate continue to 2025, it simply will not happen, and the past few years illustrate the cyclical nature of the industry. The price of oil and natural gas has plummeted unlike EPA's hypothetical projections. Operators react quickly to market forces and in many shale plays very few wells are being drilled. For many small, independent operators in various plays, they have not drilled a well in 3 or more years – yet EPA is justifying the cost of the proposed regulations on the most rapid expansion in the history of the industry. The following charts from a recent article by Energy In Depth,[12] based on EIA data, clearly illustrate the impact of market forces:

[11] Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, EPA-452/R-15-002 (Aug. 2015) at 3-9.

[12] Steve Everley, *New EPA Methane Regulations Based on Flawed Emissions Assumptions* (2015), Energy in Depth, *available at* http://energyindepth.org/national/epa-methane-regulations-flawed-emissions-assumptions/.





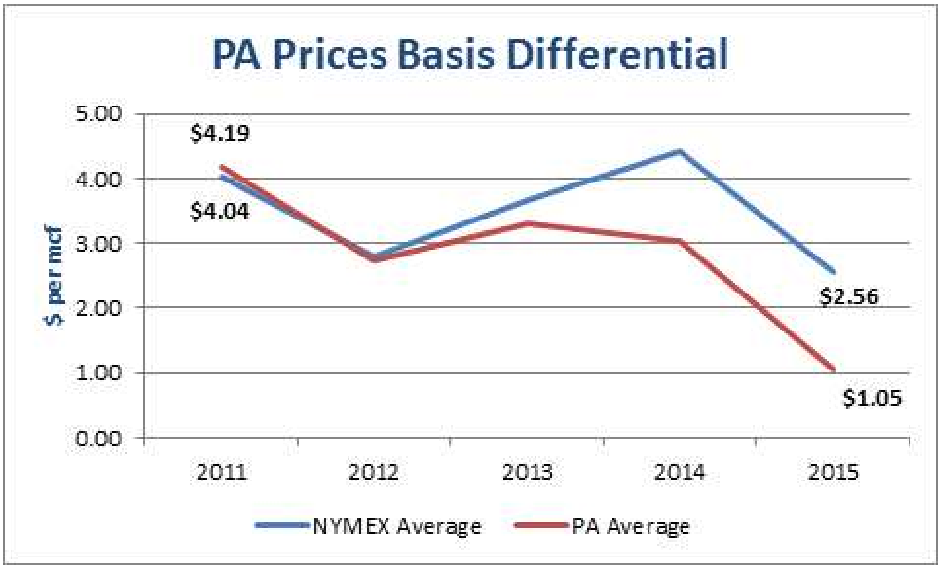
SOURCE: U.S. Energy Information Administration

EPA's cost-effectiveness analysis of the proposed regulations "applies the monetary value of the saved natural gas as an offset to the" cost of the proposed controls.[13] EPA then valued 1,000 standard cubic feet (Mcf) of natural gas at $4.00 for the RIA/cost-effectiveness analysis. The $4/Mcf assumption was based on EIA's 2014 Annual Energy Outlook forecasted

[13] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,617(Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

wellhead prices for the lower 48 states in 2020 ($4.46) and in 2025 ($5.06). EPA considered the $4/Mcf to be "conservative"[14] – presumably because of the predicted value of natural gas in 2020 and 2025. There are numerous problems with EPA assumptions. First, the New York Mercantile Exchange (NYMEX) settlement price for natural gas in October 2015 was $2.56 – 36% lower than EPA's assumed value. EPA has repeatedly indicated that it will finalize the proposed methane NSPS by the summer of 2016, and no financial institution is predicting a dramatic increase in natural gas prices between now and then. For those subject to regulations that come into effect within the next year, EPA's "conservative" estimate of $4/Mcf based on government estimates of what natural gas will cost in 2020 and 2025 is meaningless. IPAA/AXPC appreciates that the "benefit" or value of the natural gas saved by the proposed regulations occurs over the life of the well; however, the emissions from any well are heavily "front-loaded" – with the greatest production, and thus potential emissions, occurring the first few years of the well's life – long before 2020 or 2025. Smaller independents, many conventional well operators, and operators of wells that are marginally economical will not be able to weather the storm until natural gas reaches EPA's conservative value of $4/Mcf. Wells will not be drilled or will be shut in prematurely, and other companies will simply go out of business because of EPA's erroneous assumption on the price of natural gas. EPA's cost-effectiveness analysis for all proposed controls should be based on a price of natural gas that: a) more accurately reflects the price of natural gas when controls will need to be implemented, and b) accounts for the "front loading" of emissions when the price of natural gas is much lower than the $4/Mcf assumed by EPA.

EPA's assumption of $4/Mcf natural gas also fails to acknowledge or account for significant regional differences in the price of natural gas. A review of the wellhead price of natural gas in Pennsylvania provides but one of the many dramatic price variations.



[14] *Id.*

The chart above tracks the PA Price versus NYMEX average prices for the past 4 years and is current through October 2015. The "PA Price" is based on a weighted average of the Dominion South, Leidy, and Tennessee Zone 4 prices reported by Platt's *Inside FERC*. The separation of prices in Pennsylvania from the national index price is driven in large part by the lack of takeaway pipeline capacity and sheer volume of natural gas. The regional variation in price is not accounted for in EPA's cost-effectiveness analysis. Consequently EPA's inflated valuation of the price of natural gas will disproportionally impact certain regions of the country where local or regional factors result in prices that are significantly lower than the national average. EPA's cost-effectiveness analysis must take such significant regional price fluctuations into consideration when evaluating control options.

EPA is proposing regulations so fast that even it cannot keep up with the changing assumptions. Part of EPA's assumption of $4/Mcf natural gas was based on EPA's proposed Clean Power Plan.[15] However, EPA's final Clean Power Plan changed its "assumptions," and EPA now "believes" renewables will play a greater role in the country's future energy mix and natural gas prices may not reach $4/Mcf until after 2030 – well beyond the EPA's analysis for the proposed methane NSPS which ends in 2025. As Energy In Depth points out, the changing assumptions have a dramatic impact on the industry:

> According to EPA data compiled by the American Wind Energy Association (AWEA), a heavier reliance on renewables could result in natural gas prices that are at least 12 percent lower than what would be expected under EPA's base case projection [for the Clean Power Plan]. EPA also acknowledges in its RIA that a $1/Mcf change in price of natural gas translates to as much as a $19 million difference in its cost estimate. In other words, if natural gas prices averaged $3/Mcf instead of $4/Mcf, EPA could be overestimating revenue by roughly 24 percent. Based on the current 2012-2015 average natural gas spot price of $3.44/Mcf, EPA would be overestimating revenue by about $10.6 million. Under the "high renewables" scenario in the Clean Power Plan, which would depress natural gas prices even further, EPA's overestimate would be even higher.
>
> The additional costs could be devastating for an industry already suffering from a market downturn in commodity prices. An analysis by Oppenheimer & Co., for example, already found that EPA's methane rule could wipe out smaller drillers across the United States.[16]

In addition to failing to account for the changed assumptions for the price of oil and natural gas as a result of the Clean Power Plan, EPA has made no effort to account for the impact associated with proposed Ozone NAAQS. For EPA to evaluate the proposed impact of the proposed methane NSPS in a vacuum, ignoring its own significant regulatory initiatives that will have serious impacts on the price of oil and natural gas, as well as the number of entities that will be

[15] Steve Everley, *New EPA Methane Regulations Based on Flawed Emissions Assumptions* (2015), Energy in Depth, *available at* http://energyindepth.org/national/epa-methane-regulations-flawed-emissions-assumptions/.

[16] *Id.*

subject to controls, is arbitrary and capricious. Every mutual fund and investment opportunity contains the standard disclaimer along the lines of – "past performance cannot guarantee future results." The oil and natural gas industry is no different – even without EPA impacting market forces with multiple regulatory disruptions.

III. Now is Not the Time to Introduce a New Model to Justify EPA's Proposed Rules.

The benefits of the proposed rule are estimated using the social cost of methane (SC-CH_4), which has been derived from the approach the United States Government (USG) uses for estimating the social cost of carbon (SCC). However, unlike the USG's SCC which has undergone formal public comment and review, EPA's selected value for SC-CH_4 in this proposed rulemaking is arbitrarily taken from one scientific report[17] that attempts to find an equivalent SC-CH_4 from the SCC, and for which EPA only requested a "peer review" not formal public review and comment. The "peer review" was only concluded in 2014 and discussed as the basis for EPA's cost-effectiveness analysis for the first time in the RIA.[18] The model has not been evaluated by Office of Management and Budget. Providing industry a mere 60 days (plus 17) to evaluate and comment on what amounts to "new math" is inadequate. Also, the selected value of SC-CH_4 used for the Benefit-Cost Analysis in the RIA is based on an arbitrarily selected discount rate of 3 percent, which also was not proposed for public review and comment before being used to justify this proposed rulemaking.[19] Even though now EPA belatedly "seeks comments on the use of these directly modeled estimates, from the peer reviewed literature, for the social cost of non-CO_2 GHGs . . .,"[20] such a request, after EPA has already used its arbitrary value for SC-CH_4 to justify methane emissions controls on numerous methane emissions sources, is arbitrary and capricious. The only proper and legal way for EPA to apply a SC-CH_4 value to methane emissions reductions for proposed rulemakings is to publish a proposal for a SC-CH_4 value (based on scientific evidence and its arguments for a certain discount rate), take public comments on that proposed value, and finalize the value for future rulemakings. Otherwise, EPA can arbitrarily use one value of SC-CH_4 to justify controls on methane emissions from one industrial sector source and then turn-around later and use some other arbitrary value for another industrial sector source, all presumably justified by taking comment on the arbitrary value already used to justify the proposed regulations.

---

[17] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,655 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

[18] Regulatory Impact Analysis of the Proposed Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, EPA-452/R-15-002 (Aug. 2015).

[19] Exacerbating the arbitrary nature of the 3% discount rate for benefits, EPA inconsistently and inappropriately selected a 7% discount rate for the cost to industry. EPA's unjustified use of different discount rates arbitrarily and capriciously overstates the benefits compared to the costs.

[20] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,656 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

IV. Overarching Comments Particular to the Proposed NSPS for Methane, Subpart OOOOa.

In Sections V and VI of the preamble to the proposed NSPS, EPA dedicates considerable verbiage attempting to justify the need and its legal authority to regulate methane from sources in the oil and natural gas sector. IPAA/AXPC disagrees with both the need and EPA's authority to regulate methane for the reasons set forth below.

EPA's interest in regulating methane is clearly a political decision rather than an environmentally driven decision. Its genesis can be easily seen in the strident demands from anti-fossil energy groups with agendas not to manage industrial emissions but to prevent the development of oil and natural gas. Groups like the Sierra Club have policies that are clear:

> There are no "clean" fossil fuels. The Sierra Club is committed to eliminating the use of fossil fuels, including coal, natural gas and oil, as soon as possible . . . Methane released via extraction and transport is 86 times more potent as a greenhouse gas than CO_2 over a 20-year time frame. The climate-disruption impacts from methane and carbon dioxide emitted by extraction, transport and burning clearly point to the urgent need of keeping fossil fuels in the ground.[21]

This group, along with others, made their demands known to the EPA in multiple meetings and letters, including a December 2013 letter stating the following:

> We commend EPA for updating its VOCs performance standards for this industry in 2012, but the job is far from finished. While some reductions in methane emissions will be achieved as a co-benefit of these 2012 rules, many emission sources are not adequately addressed, such as the vast network of equipment that was installed before those rules went into effect. EPA needs to take immediate steps to produce regulations to directly reduce methane pollution from new and existing equipment from this industry.[22]

Once demanded, the issue of direct methane regulation became the pivot point for development of the current regulatory proposals. As discussed below, the drive for direct methane regulations for the oil and natural gas sector is driven by atmospherics and philosophy, not science or increased environmental benefit.

---

[21] *Sierra Club to Big Oil: There are no 'clean' fossil fuels*. Sierra Club (Apr. 21, 2015) *available at* http://angeles.sierraclub.org/news/blog/2015/04/sierra_club_big_oil_there_are_no_clean_fossil_fuels.

[22] Earthworks, *et al*. Interior Secretary Jewell, EPA Administrator McCarty to Curb Methane Emissions from Oil and Gas Industry, Earthworks (Dec. 5, 2013) *available at* https://www.earthworksaction.org/library/detail/open_letter_to_interior_secretary_jewell_epa_administrator_mccarthy_to_curb#.VmHY97Eo74Y.

In reality, EPA was forced to propose regulations to satisfy a political agenda that is governed more by what "we [EPA] believe that the industry can bear . . . and survive."[23] EPA's decision to promulgate methane standards from the exploration and production segment of the oil and natural gas sector is arbitrary and capricious. EPA states that it "believe[s] it is important to regulate methane from the oil and gas sources already regulated for VOC emissions to provide more consistency across the category . . . ."[24] Yet in the very same sentence EPA admits "that the best system of emission reductions (BSER) for methane for all these sources is the same as the BSER for VOC."[25] EPA continues that the BSER for the previously unregulated sources is the same for VOCs and methane. Simply put, the controls on the targeted emissions sources to reduce VOCs are the same as the controls to reduce methane – no more, no less. The "gain" – according to EPA – of adding yet another Subpart of regulations to the already extensive 40 C.F.R Part 60 is "consistency." What EPA chooses to ignore in its preamble discussion is the inevitable "loss" or cost to the industry associated with the regulation of existing sources under Section 111(d).

EPA is silent as to its "beliefs" on whether the industry can "survive" the cost and burden of regulation of existing sources under Section 111(d). This silence is notable and troubling. Clearly, since EPA demonstrates that the technologies used to regulate methane emissions are identical to those for VOC emissions, EPA's choice to expand its regulations to directly regulate methane can only be interpreted as opening a potential pathway to Section 111(d) regulations as the anti-fossil energy organizations demanded. And, while EPA fails to even mention Section 111(d), it must certainly know – based on the demand that existing methane sources must be regulated – that it will face efforts to force such regulation. EPA will surely respond that it will conduct the necessary cost-benefit analysis when it is "forced" to promulgate existing source standards under Section 111(d). Without debating the legalities as to EPA's duties under Section 111(d), this Administration has demonstrated time and time again its propensity to feign resistance to non-governmental organizations' (NGO) "demands" and enter into consent decrees with unreasonable short time periods to promulgate regulations. The irony is that EPA's rationale assumes that the underlying Section 111(b) regulations were necessary in the first place. What has the environment gained (above the benefits gained from VOCs) from regulating methane emissions from exploration and production directly? Nothing. EPA has admitted it. The controls are the same – equally efficient at controlling VOCs and methane. The cost? EPA relies heavily on its original cost-effectiveness analysis for the Subpart OOOO VOC regulations finalized in 2012 and engages in additional analysis discussed in Section VIII of the preamble, concluding that the proposed controls "for methane" are also cost-effective. But nowhere does EPA take into account the cost to the industry associated with the regulations that will likely be forced upon existing sources in this source category. Despite all of the complicated calculations and analyses, the simple fact remains that the controls for VOCs and methane from the targeted sources are the same. There is no demonstrated "need" or unique benefit associated with an additional set of standards specifically for methane. The true cost of the proposed methane

---

[23] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,629 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60)

[24] *Id*. at 56,595.

[25] *Id*.

regulations is incomplete and unknown without considering the cost associated with regulating existing sources under Section 111(d).

"Consistency across the category" is an insufficient justification. Historically, EPA has tailored new source performance standards to subcategories or segments within a larger, overarching category. One needs to look no farther than Subpart D and its progeny for Steam Generating Units or Subpart E for Municipal Waste Combustors. EPA has shown it can be very creative in tailoring requirements to subcategories or segments within a listed category. Since the Administration first hinted at regulating methane directly from the exploration and production segment, IPAA/AXPC has advocated that such direct regulation was unnecessary, as the controls for VOCs were exactly the same as for methane. EPA acknowledged as much in Section VII in the preamble and stated "[w]e anticipate that these stakeholders will express their views during the comment period."[26] IPAA/AXPC questions the appropriateness of EPA's decision to essentially ignore a central premise of two federal trade associations that represent approximately 54% of oil and 85% of natural gas exploration and production capacity of this country. Is it appropriate for IPAA/AXPC to guess as to EPA's reasoning and justification? Much of EPA's 67-page preamble is dedicated to justifying its legal basis for regulating methane directly and the cost-effectiveness of the proposed controls. It fails to address in any meaningful way why it is necessary or justified to promulgate methane standards from the exploration and production segment. EPA's justification boils down to: 1) EPA assumes it is has the legal authority to do so; 2) EPA has placed a high value on "consistency" within the source category; and 3) EPA "believes" the industry can "survive." EPA is on much stronger legal footing addressing segments or subcategories differently within the oil and natural gas sector than asserting it does not need a separate endangerment finding for methane. EPA's insistence, without explanation, on promulgating methane standards for exploration and production sources, when the controls are exactly the same, needlessly increases the regulatory burden on everyone – the regulated and the regulator. IPAA/AXPC should not have to guess until the rule is finalized and potentially litigate an issue that has been clearly articulated to EPA, the Small Business Administration, and the Office of Management and Budget long before the rule was even proposed.

In Section V and VI, EPA indicates it is responding to and granting a Petition for Reconsideration associated with the 2012 NSPS Subpart OOOO for VOCs which requested the promulgation of NSPS for methane. The key elements outlined as EPA's reasoning for granting reconsideration are:

- "the wealth of additional information now available to us . . ."[27]
- "[t]he oil and natural gas industry is one of the largest emitters of methane, a GHG with a global warming potential more than 25 times greater than that of carbon dioxide."[28]

---

[26] *Id*. at 56,609.

[27] *Id*. at 56,599.

[28] *Id*.

- "because the EPA is not listing a new source category in this rule, the EPA is not required to make a new endangerment finding with regard to oil and natural gas source category in order to establish standards of performance for the methane from those sources."[29]
- "a number of major scientific assessments have been released that improve understanding of the climate system and strengthen the case that GHGs endanger public health and welfare for current and future generations."[30]

EPA then dedicates approximately 10 pages of the preamble to defending their position that a separate endangerment finding strictly for methane is not needed (and backfilling in case they are wrong), making the case for global climate change from GHGs, and presenting various charts on U.S. methane emissions. Unlike the remaining sections of the preamble (approximately 55 pages), in which EPA seeks specific comments on particular issues at least 50 different times, EPA did not seek comment once in Sections V and VI.

While IPAA/AXPC has not attempted to take issue with or refute every inaccuracy or assertion contained within these sections of the preamble, EPA's key elements are addressed briefly below:

- IPAA/AXPC agrees there is a wealth of additional information – much of it taking issue with anthropogenic global warming. A cursory review of the website Watts Up With That, http://wattsupwiththat.com/, reveals the science is not "settled" as EPA would have one believe.
- While EPA alleges that the oil and natural gas sector is one of the "largest emitters of methane", EPA's own numbers illustrate that in 2013, the oil and natural gas sector accounted for 2.22% of the Total U.S. GHG Inventory.[31] And as stated earlier, the exploration and production segment is only 1.07% of that 2.22%. The oft-quoted greenhouse gas multiplier is subject to manipulation based on the timeframe used to make the carbon dioxide comparison, and the "legacy warming from fugitive methane is minuscule compared to that of carbon dioxide."[32]
- The adequacy of EPA's endangerment finding is far from settled and will certainly be subject to legal challenge upon final promulgation of this rule if EPA persists with its intention to regulate methane directly.[33]
- In supporting its claim that EPA better understands climate change, it cites the Intergovernmental Panel on Climate Change's (IPCC) 2013-2014 Fifth Assessment Report (AR5). Many of these "citations" or statements to support EPA's position are

[29] *Id*. at 56,601.

[30] *Id*. at 56602.

[31] *Id*. at 56,608.

[32] Elizabeth A. Muller and Richard A. Muller, *The Facts About Fugitive Methane*, Centre for Policy Studies (Oct. 2015) *available at* http://www.cps.org.uk/files/reports/original/151022155129-TheFactsofFugitiveMethane.pdf.

[33] David Yaussy and Elizabeth Turgeon. *Unringing the Bell: Time for EPA to Reconsider Its Greenhouse Gas Endangerment Finding*, 116 W.Va. L. Rev. 1007 (2014).

from the Summary for Policy Makers, which was written by the policy makers, not the scientists who authored the report.[34] Judith Curry, former Chair of the School of Earth and Atmospheric Sciences at the Georgia Institute of Technology, evaluated and commented on the AR5, not the Summary for Policy Makers, and noted various factors that evidence a weakening of the case for anthropogenic global warming:

  - Lack of warming since 1998 and growing discrepancies with climate model projections
  - Evidence of decreased climate sensitivity to increases in CO_2
  - Evidence that sea level rise from 1920-1950 is of the same magnitude in 1993-2012
  - Increasing Antarctic sea ice extent
  - Low confidence in attributing extreme weather events to anthropogenic global warming.[35]

- EPA also relies heavily on the U.S. Global Change Research Program's (USGCRP) 2014 National Climate Assessment, Climate Change Impacts in the United States (NCA3), to support its alleged climate change impacts – ranging from decreased Artic summer sea ice to increased sea levels to drier/more intense storms, as well as greater impact to children and the elderly.
  - Studies not cited by EPA demonstrate no significant changes or deviations from cyclical patterns in the quantity of ice.[36]
  - As to the frequency and intensity of storms, other studies not cited by EPA raise questions regarding storm predictability: "October marks a continuation of a record-long major hurricane (Category 3 or stronger) landfall drought in the United States. The last major hurricane to make landfall in the U.S. was Wilma on October 24, 2005. This major hurricane drought surpassed the length of the eight-years from 1861-1868 when no major hurricane struck the United States' coast. On average, a major hurricane makes landfall in the U.S. about once every three years. The reliable record of landfalling hurricanes in the U.S. dates back to 1851."[37] "The bar [see footnote] charts

[34] Wim Rost, *IPCC ≠ Science ↔ IPCC = Government*, Watts Up With That (Nov. 29, 2015) *available at* http://wattsupwiththat.com/2015/11/29/ipcc-science-ipcc-government/.

[35] Judith Curry, *IPCC AR5 Weakens the Case for AGW*, Climate Etc. (Jan 6, 2014) *available at* http://judithcurry.com/2014/01/06/ipcc-ar5-weakens-the-case-for-agw/.

[36] http://ocean.dmi.dk/arctic/plots/icecover/icecover_current_new.png; http://nsidc.org/data/seaice_index/images/daily_images/S_stddev_timeseries.png

[37] National Oceanic and Atmospheric Administration , National Centers for Environmental Information, State of the Climate: Hurricanes and Tropical Storms for October 2015 (Nov. 2015) *available at* https://www.ncdc.noaa.gov/sotc/tropical-cyclones/201510. While other ranking metrics for hurricane's are being developed, the National Hurricane Center for the National Oceanic and Atmospheric Administration and EPA continue to regularly rely on an cite to the Saffir-Simpson Hurricane Wind Scale to compare the potential impacts of hurricanes.

> below indicate there has been little trend in the frequency of the stronger tornadoes over the past 55 years."[38]

The title of Section V of the preamble is "Why is the EPA Proposing to Establish Methane Standards in the Oil and Natural Gas NSPS?" EPA's stated concerns are ostensibly laudable. However, nothing set forth in Section V or Section VI of the preamble justifies or necessitates separate methane NSPS from the exploration and production sector.

A. Consistent with the Clean Air Act, State Programs Should Control

The CAA is structured such that states should have primacy and be primarily responsible for compliance with the requirements of the Act. Many of the states with the most active shale plays have implemented state regulations to address many of the emissions sources targeted in the proposed Subpart OOOOa regulations. States with state permitting programs and/or State Implementation Plans (SIPs) that contain limits on sources that are legally and practically enforceable should be deemed sufficient for overlapping and duplicative requirements in Subpart OOOO and the finalized version of Subpart OOOOa. EPA should defer to existing state regulations to the greatest extent possible to deem compliance with state regulations on the same sources as constituting compliance with the final Subpart OOOOa regulations. Duplication and inconsistency between state and federal regulations simply add to the cost of compliance with little to no additional benefit to the environment. To the extent EPA does not allow for such provisions, EPA should demonstrate that the duplicate or "more stringent" regulations that EPA is promulgating are incrementally cost-effective: meaning that the cost associated with the duplicative or inconsistent federal control requirement is cost-effective based on the incremental environmental benefit above the state regulation already in place or deem compliance with the state regulations as compliance with Subpart OOOOa. EPA must justify with an *incremental* cost and benefit analysis any proposal to impose additional federal regulations that it deems more stringent than existing state regulations.

B. Fugitive Emissions at Well Sites and Compressor Stations

Managing fugitive emissions or "leaks" from the oil and natural gas sector appeals to common sense. Leaks associated with natural gas operations represent safety concerns, negative impacts to the environment, and are wasteful from an economic standpoint. The industry has relied on audio/visual/olfactory (AVO) inspections for many years, and only recently has the industry focused considerable attention on technological advances to detect leaks. It is an emerging process – both in terms of technology and methodology (regulatory and corporate management). EPA's preamble bears this fact out with the number of specific requests for "comment" on the leak detection aspect of the proposal. IPAA/AXPC supports, in concept, the ability to satisfy the leak detection and repair (LDAR) requirements of the proposal with an appropriate "corporate fugitive monitoring plan," but a 60-day comment period (plus a random 17 days halfway through the comment period) is not enough time to create and implement such a

[38] National Oceanic and Atmospheric Administration, National Centers for Environmental Information, Historical Records and Trends, *available at* https://www.ncdc.noaa.gov/climate-information/extreme-events/us-tornado-climatology/trends.

program. Additionally, recent data and studies demonstrate that production fugitive emissions are characterized by a few sources ("fat tails") representing the overwhelming majority of emissions.[39]

A handful of states are taking the lead on creating regulatory frameworks, each of which is different, and none of which follows the proposed EPA framework. Experience with the state programs is indicating that correction of fat tail emissions results in effective management of fugitive sources and, once corrected, the need for full-blown inspections/surveys more often than an annual frequency is unjustified. Even the states with the most aggressive LDAR programs are not focused on quantifying the total amount of methane "saved." The very nature of fugitive emissions makes it very difficult to quantify how much gas is being "saved." It is not as simple as a single point source with consistent flow where one can easily measure the emissions before and after controls are "bolted on" a stack or emission point. The component count at most facilities is likely in the hundreds to thousands, with only a very small percentage of the components leaking. For those that are leaking, the quantity of gas leaking varies considerably. Nonetheless, EPA crunched some numbers in a hypothetical world and assigned some value to the natural gas that is saved. In reality, very few companies will realize any change in the sales meter pre- and post-LDAR. The savings are largely illusionary to the average operator. The value of the natural gas "saved" through the LDAR programs is highly speculative. In addition, EPA did not account for the size of the facility when estimating the percent savings. EPA's percentage saved calculations are based on Colorado's regulations and related data. Colorado's 80% reduction, which EPA adopts, is based on monthly inspections for facilities with less than 50 tons per year. EPA assumes, with no additional support, that their proposed regulations can achieve an 80% reduction from quarterly inspections for all facilities, regardless of size. IPAA/AXPC questions the validity of EPA's cost-effectiveness analysis for its proposed LDAR regulations.

EPA should withdraw the proposed LDAR NSPS because it has not been developed based on the emerging experiences with fugitive emissions management programs, it locks in a technology approach that may be cost ineffective as experience with state programs evolves, and it would stifle the development of better approaches. Instead, EPA should work with states to learn from their programs and provide for a flexible voluntary fugitive emissions program in the Methane Challenge that would build a basis for a cost-effective NSPS in the future, if one is needed. At a minimum, implementation of any program should be delayed and EPA should work with industry to establish the necessary elements of a corporate fugitive monitoring plan that companies could adopt and customize to meet their particular needs while satisfying EPA's LDAR requirements. This performance-based approach would be the most effective and efficient.

Other than the handful of companies that provide the optical gas imaging (OGI) technology, industry is united in its position that EPA should not select or dictate the technology for detecting leaks. The concept behind NSPS is setting a performance standard that must be

[39] David T. Allen, *et al*. Measurements of methane emissions at natural gas production sites in the United States, Proceedings of the National Academy of Sciences of the United States of America (Aug. 19, 2013) *available at* http://www.pnas.org/content/110/44/17768.

met – not dictating a particular technology. Dictating a particular technology stifles innovation. There are approximately a half dozen or more additional technologies/techniques that are being marketed and/or developed including, but not limited to: tunable diode laser absorption spectroscopy; 3-channel non-dispersive gas correlation infrared spectrometer; mid-infrared laser-based differential absorption light detection and ranging; simultaneous-view gas correlation passive infrared radiometer; acoustic gas lead detectors; and remote methane leak detectors. These are in addition to the existing Method 21 procedure that some companies find workable and preferable. The need and motivation to "build a better mouse trap" will cease to exist if EPA dictates the technology, and there is no reason for EPA to select one technology.

OGI/forward looking infrared (FLIR) technology suffers from numerous limitations. Perhaps most importantly, it is not inherently safe – if not used properly on site, it could cause an explosion. Additionally, the results of the camera, the "pictures", are difficult to interpret and subject to misinterpretation, e.g., what appears to be a leak could simply be a heat plume. These problems are exacerbated in windy and/or cold conditions that are prevalent in a number of the shale plays. The technology is prohibitively expensive to smaller operators, and there is a limited supply of qualified service providers that can afford the camera. Even for the larger companies, at approximately $120,000 a camera, there will be a limited supply. For companies with diverse geographic locations, it will be difficult to comply with the short survey timeframes set forth in the proposal. The proposed regulations also require survey pictures to contain GPS coordinates. Some of the cameras do not have that function, thus requiring another device to comply with the regulations. Finally, the OGI technology is not a quantitative tool – it is not capable of determining how much natural gas is leaking.

As discussed above, a number of states are taking the lead on LDAR programs and are learning how to effectively and efficiently implement controls and administer surveys. Despite repeated requests by IPAA during the Small Business Advocacy Review Panel process and other trade association requests for EPA's proposal to be consistent with and not duplicative of existing state LDAR programs, EPA's proposal runs roughshod over existing state programs. Inconsistencies and duplication in the proposed regulations and existing programs are burdensome, inefficient and costly – especially to small entities and independent operators. IPAA/AXPC specifically incorporates by reference the comments on the NSPS proposal of Anadarko which highlight the inconsistencies between the proposed Subpart OOOOa and existing regulations in Colorado and Pennsylvania. EPA's proposed regulations essentially punish states and operators within those states that proactively moved to address fugitive admissions. Such an approach does not make for sound policy. States with existing programs should be deemed sufficient, and compliance with the state program should be deemed as compliance with the finalized federal program. This is not a new concept in the context of EPA's NSPS for the oil and natural gas industry, and EPA should revise the proposed regulations to model the exemption for storage vessels in Subpart OOOO and deem legally and practically enforceable state LDAR programs to suffice for the proposed federal regulations. Such revisions would greatly reduce the regulatory burden for sources located in states that have proactively addressed fugitive emissions from the oil and gas sector. To the extent a party (whether EPA or a third party) believes an existing state program is inadequate, the burden should be placed on the entity making the allegation, and EPA should establish a process to address the complaint.

Additionally, consistent with the CAA, the state programs should control, and EPA should implement procedures in the final regulations for states to submit for approval a state-based LDAR program that is deemed sufficient to satisfy EPA's final LDAR requirements.

Another issue advocated by IPAA/AXPC and/or member companies prior to publication of the proposed rule was to *not* base LDAR requirements on arbitrary component count or percentage of components leaking at a given site – yet that is exactly what EPA proposed. EPA suggests that its proposal, which bases the frequency of surveys on the percentage of leaking components, provides an "incentive" for companies to be more vigilant in their identification and repair of leaks. As discussed above, the incentive to identify and repair leaks already exists, as there is a strong safety and economic incentive. EPA's proposal based on percentage of leaking components creates a recordkeeping nightmare. The regulations are less than clear as to what constitutes a "facility" in terms of where to draw the line and stop the component count. As a result of the ambiguity in the proposal, it is difficult to evaluate if EPA's assumptions on components per well count are accurate. There is tremendous variability in the number of wells and types of equipment on well sites. For EPA to base its cost effectiveness on a "model well pad" is problematic. Member companies report component counts in the hundreds to thousands of components. Such a wide range is in part, a function of lack of clarity in the regulations and also calls into question the accuracy of EPA cost-effectiveness assumptions on a model plant. If EPA persists with a percent-leaking methodology, the regulations need to be clarified on what components are to be counted and how to define the limits of the facility for the component count. EPA's own evaluation concluded that quarterly surveys of the intensity proposed are not cost-effective. Yet, if more than 3% of the components are leaking, the proposed regulations require quarterly surveys. If quarterly surveys are not cost-effective, having more than 3% of the components leaking does not somehow make the quarterly surveys become cost-effective. Additionally, there is no direct correlation between the number of leaking components and quantity of emissions, so basing the frequency on the percentage of leaking components does not necessarily mean the program will be more effective at preventing fugitive emissions. While there is no direct correlation between the number of components and quantity of emissions, the component count/percent leaking ratio directly impacts the recording keeping requirements – again with no demonstrated reduction in emissions. It is just more paperwork compliance for operators.

Furthermore, leaks are often related to some sort of malfunction and once fixed, stay fixed such that there is no need or rational basis to increase the survey frequency. As EPA discussed in the preamble, experience with the state programs demonstrates there are "gross emitters" or "super emitters" that represent a very large percentage of the overall fugitive emissions profile (consistent with the fat tail issues discussed above). Preliminary information from companies with operations in states with aggressive LDAR programs already in place indicates treating every component "equally" is an inefficient use of limited resources. This information suggests that components subjected to constant or frequent vibration (such as components associated with a compressor) are much more likely to have leaks than say, threaded connections. And in terms of total component count at a given facility, there are likely to be many more threaded connections than the components most likely to leak at the relatively few compressors. Even if it is difficult to predict "gross emitters" or "super emitters" at any given facility, the knowledge gained from sources within states with existing LDAR programs suggests that treating all components equally and basing the frequency of surveys on leaking component percentages is inefficient from an emissions reduction perspective and extremely burdensome and costly – especially to small entities. Again, more time to craft a regulatory program designed to identify and repair gross emitters would be preferred by IPAA/AXPC.

Basing the frequency of surveys on the percent of components leaking exemplifies that EPA is largely guessing at what constitutes an appropriate LDAR program. EPA should not rush to judgment and instead learn from the state programs to determine the most effective and efficient way to reduce leaks. Alternatives include a performance-based approach such as that in Wyoming, basing the survey frequency on the size of the facility or the quantity of emissions leaked or perhaps a combination of a more technology-based annual survey with periodic AVO "inspections" between annual surveys. If EPA persists with the percentage-leaking-component approach, flexibility should be built into the program that companies could commit to semi-annual surveys and not be subject to fluctuation from quarterly to annual surveys based on the number of components leaking. For some companies, the ability to plan for semi-annual reporting without the risk of quarterly monitoring would be more beneficial than the changing requirements and potential cost saving of annual surveying. However, for some smaller entities or independent operators, the ability to reduce surveys to an annual basis might be beneficial. Sources should be given the flexibility to choose. Flexibility in complying with the LDAR program will help reduce the cost and burden.

Individual components that are to be included for "fugitive" emissions monitoring must be better defined and differentiated from components that are designed to emit a certain amount of natural gas under certain circumstances. Further, components of the storage vessels, e.g., closed cover/vent/control systems, already covered under Subpart OOOO for storage vessels should not be subject to additional requirements. As some states have done, EPA should more clearly define and exclude components that are designed to release pressure for safety reasons, e.g., thief hatches and enardo valves.

Dictating a particular technology (OGI/FLIR) and then requiring the initial survey be conducted within 30 days (and repaired within 15 days) is an unreasonably tight time period – especially for smaller entities and operations with disperse and remote locations. These timeframes should be extended to 60 and 30 days, respectively. If EPA persists with the unrealistic time frames, a mechanism allowing for a "variance" on the time frames when certain circumstances exist should be built into the regulations. Even with companies with the resources to purchase a camera, their operations may be geographically dispersed or weather conditions are uncooperative such that they cannot realistically get from one location to the other. Smaller entities and some independent operators who cannot afford the dictated technology are then at the mercy of the market to comply within 30 days. Especially during the early implementation of the new rules, many sources are likely to incur enforcement/liability through no fault of their own due to an inability to purchase the technology or hire service providers with the necessary capabilities.

EPA's cost-effectiveness for the proposed LDAR program requirements is fundamentally flawed because it merely looks at the cost of conducting the survey and fails to accurately account for the increased record-keeping and reporting requirements. EPA's analysis is myopically focused on a straight up comparison of "cost-effectiveness" for semi-annual surveys versus annual and opts for semi-annual requirements because the relative cost-effectiveness is the same: $2,475 for annual versus $2,768 for annual under the single pollutant approach at the well site.[40] EPA conducted similar comparisons for the multi-pollutant approach at the well site (as well as both comparisons at a compressor station).[41] In every instance the annual survey was more cost-effective but EPA selected the semi-annual surveying because the cost/ton removed was similar. There are two problems with that philosophy. First – in selecting the semi-annual requirement, EPA basically double the cost of the requirement to industry. Second, the theoretical or modeled additional reduction in emissions is a very small percentage of the overall emission reductions associated with the proposed regulations. The additional cost associated with the annual survey requirement is substantial while the increased benefit to the environment is minimal. The additional regulatory burden will be disproportionately felt by small entities. The proposed LDAR requirements basically require all companies, regardless of size, to implement costly information systems to track and monitor compliance. For example, one of the larger, more sophisticated operators with a data management system already in place incurred an additional $10,000 in external costs associated with developing new or revised software, and an additional $37,000 associated with internal set-up costs and employee time focused on implementation. These costs were associated with complying with Colorado's LDAR program in a small gas field of 174 wells and, as indicated, were in addition to an existing management system at an estimated cost of $80,000 annually. It does not appear that costs such as these were considered in EPA's cost-effectiveness analysis. EPA's proposed requirements appear to be based on what is required at natural gas plants, and expanding that level of detail to remote, un-manned production sites is inappropriate. Such level of detail is not warranted nor has the cost been adequately justified – especially over the life of the well. The majority of the "benefit" associated with the surveying is on the initial startup of a well (or startup after modifications). It is impossible to calculate an accurate annual gas recovery rate over the life of a well site.

The new record-keeping requirements associated with the LDAR are particularly burdensome to smaller operators with limited staff. For example, the preamble provides limited to no justification for requiring the date-stamped digital photograph. If EPA retains the burdensome record-keeping requirements, companies should be allowed to keep the records on site or at a regional field office and produce them upon request. Companies should not be required to submit electronically or manually to the permitting agency. EPA requested comment on "ways to minimize recordkeeping and reporting burden." As discussed above, EPA should evaluate existing state requirements and liberally deem them sufficient for purposes of Subpart OOOOa and establish a mechanism for states to implement their own programs that supersede and satisfy Subpart OOOOa.

---

[40] Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Sector: Standards for Crude Oil and Natural Gas Facilities – Background Technical Support Document for the Proposed New Source Performance Standards 40 CFR Part 60, subpart OOOOa (Aug. 2015) (hereinafter, TSD), at Table 5-14.

[41] *Id.* at Tables 5-15, 5-17, 5-18.

IPAA/AXPC supports the limited exclusions from the LDAR requirements that EPA has proposed but requests certain clarifications and expansion of the exclusions. Excluding low production well sites – defined as the "average combined oil and natural gas production for the oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production"[42] -- is extremely helpful for small entities and smaller independent operators. IPAA/AXPC understands the 15 boe is also an "off ramp" – that is, when a well drops below 15 boe, it is no longer subject to the LDAR requirements. IPAA/AXPC requests the regulatory language be revised to indicate that when a well drops below 15 boe, based on a 30-day average production, the LDAR requirements no longer apply. EPA should provide an additional exclusion for well sites with component counts below EPA's model well site: below 548 components for gas well sites and below 135 components for oil well sites should be excluded from the LDAR requirements.[43] EPA concluded that it is not cost effective to implement the proposed LDAR requirements on sites with lower well component counts and therefore those well sites should be excluded. Such exclusion would help all producers but would have greatest benefit to small entities that are likely to have smaller well sites. IPAA/AXPC also supports EPA's proposed exclusion for well sites with extremely dry gas where only the wellhead exists and there is no "ancillary equipment." IPAA/AXPC requests clarification that a meter and drip present at the well site do not constitute "ancillary equipment." Finally, in response to an EPA request for comment, IPAA/AXPC suggests that the LDAR requirements should only apply to those components that are directly connected to the fractured, refractured, or added well and should not apply to tank batteries or other equipment off the well pad which may receive fluids from the fractured, refractured or added well.

C. Oil Well Reduced Emission Completions

As with the proposed LDAR requirements, in its rush to promulgate regulations aimed at additional sources of VOCs and methane, EPA assumed that reduced emission completions (RECs) on oil wells are essentially the "same" as RECs on natural gas wells. Unlike a natural gas well, where the price of natural gas dictates many operational decisions, the economic driver for oil wells is the price and volume of oil – not natural gas. When EPA promulgated Subpart OOOO regulations for VOCs and RECs on natural gas wells, EPA indicated it did not have enough information to determine if oil well RECs were cost-effective.[44] The cost-effectiveness of oil well RECs was also raised by EPA in the Methane "White Papers" released on April 15, 2014.[45] IPAA/AXPC and individual member companies submitted comments on EPA's oil well

[42] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,612 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

[43] TSD at Table 25-1.

[44] Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 77 Fed. Reg. 49,490 ,49516 (Aug. 16, 2012)

[45] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production* (Apr. 2014), *available at* http://www3.epa.gov/airquality/oilandgas/2014papers/20140415completions.pdf.

REC White Paper - identifying concerns with the cost-effectiveness of RECs for oil wells.[46] EPA's preamble discussion in Section VII of the proposed standards for oil well RECs makes a general reference to the Technical Support Document (TSD) for the current proposal in terms of justifying its best system of emissions reduction determination, but there is no updated cost/benefit data cited in the proposal. The citations refer back to the "2012 NSPS evaluation." It appears EPA has failed to cite any new or additional information collected since the 2012 evaluation to support the cost-effectiveness of the proposed oil well REC requirements. The economics of natural gas RECs are different and do not support oil well REC requirements.

Based on the preamble discussion of undertaking of an oil well REC, EPA assumes the process is essentially the same, but this is not necessarily the case. While certain wells will have relatively clear initial and separation flowback stages like natural gas wells, there are instances where there is no separation flowback stage owing to the lack of gas or quality of gas such that operation of a separator is not feasible. On certain wells, the initial flowback stage is followed by directing the flowback immediately into the production battery. Perhaps more so than with RECs on natural gas wells, the various stages of flowback on oil wells can be difficult to clearly delineate, and the ability to utilize a separator is a function of engineering judgment. IPAA/AXPC supports the concept of identifying two stages of flowback, with no control placed on the associated gas with oil well completions during the initial flowback stage. However, there will be situations where certain oil well completions will not experience a separation flowback stage.

In the preamble discussion of the REC requirements for both subcategory 1 and subcategory 2 wells, EPA expressed a clear intention to allow for venting of emissions in lieu of combustion during periods when the flowback gas is noncombustible.[47] This intent is particularly important for completions utilizing inert gas, such as nitrogen or nitrogen foam, instead of water as the medium for the fracturing process. The inert gases present in the flowback make the gas, for a period of time, "not of salable quality" and technically infeasible. The relevant provisions of the proposed regulations at 40 C.F.R. 60.5375a(a)(3) and 40 C.F.R. 60.5375a(f)(2) should be modified at the end of the provision to allow for venting when "*it is technically infeasible due to inert gas concentration*." The addition of this phrase at the end of the current proposed language would eliminate any ambiguity as to EPA's intent.

IPAA/AXPC agrees that the feasibility of oil RECs should take into consideration the availability of gathering lines and that it is not as simple as a linear distance from a gathering line. As EPA acknowledges in the preamble, there are many factors that determine gathering line availability – not just distance. There are other considerations that drive the decision to recover gas which include, but are not limited to, the following factors: gas volume, gas pressure, gas Btu content, gas liquid content, sales line gas pressure requirements, moisture

[46] Comments of the Independent Petroleum Association of America and Western Energy Alliance on White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector per the Climate Action Plan Strategy to Reduce Methane Emissions (June 16, 2014).

[47] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,630, 56,632 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

requirements, compression, and current takeaway capacity of existing gathering systems. One workable approach that might assist regulators is to use a linear distance, such as a ¼ mile, to presume that flaring is permitted because it is generally agreed that, beyond that distance a gathering line is not available. The converse, a gathering line within a ¼ mile, should not be assumed to be available prompting a case-by-case determination based on the factors detailed above. Again, IPAA/AXPC supports EPA's acknowledgment that the availability of a gathering line must be considered in evaluating the feasibility of an oil well completion but that it is not as simple as designating a linear cut point.

IPAA/AXPC supports the various exclusions from the oil well REC requirements for oil wells less than 15 boe; wells with a gas-to-oil ratio (GOR) of 300 or less; and the low-pressure well. Although not an exact science, operators can make engineering judgments and estimations based on experience in a developed formation. If the well initially exceeds 15 boe, a potential solution is to allow the operator to temporarily shut in the well and bring in REC equipment or limit the production such that the well does not make more than 15 boe for any measurement period as long as the average rate of the averaging period is 15 boe or less. In the event that the operator, based on strong well performance, decides to bring in REC equipment, he could earn a 0 bopd credit to the averaging period for every day the REC is used. IPAA supports the inclusion of an exclusion for a "low-pressure oil well" but it is not appropriate to utilize the definition for a "low-pressure gas well." Oil and water are fairly equivalent on their impact on the intent of this low-well pressure exemption in the early phases of flowback, and the water/oil ratio will change significantly during the early flowback periods for hydraulically fractured wells. The main difference is that, once the hydraulic fracture load stops coming back, a gas well will typically have much less liquids in the production tubing, making the surface pressure actually higher for the gas well vs. an oil well. This difference would be reflected in the 0.038 number which represents the gas gradient in the well, which would impart a back pressure. For oil wells this back pressure would be higher, i.e. more liquids in the tubing, and this factor should be increased. For example a well making 15 boe up 2-3/8" production tubing at a 300 GOR could have a gradient of 5 to 10 times as much. The new record-keeping requirements associated with oil RECs (but also applicable to natural gas RECs) disproportionately impact the smaller, independent operators (conventional operations).

Finally, IPAA/AXPC continues to believe EPA's cost-effectiveness analysis for oil well completions is flawed because it is taking "credit" for well completions industry has already done or will do regardless of regulations. IPAA and WEA filed extensive comments on EPA's oil well completion White Paper on June 16, 2014.[48] The issues raised in that process have not been adequately addressed by EPA in the RIA or Technical Support Document for this rulemaking. The most relevant provisions of those comments are reproduced below:

> Finally, we question the need or benefit of EPA requiring reduced RECs or combustions devices/flares at oil wells as operators are already engaged in such

[48] Comments of the Independent Petroleum Association of America and Western Energy Alliance on White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector per the Climate Action Plan Strategy to Reduce Methane Emissions (June 16, 2014). The Comments of AXPC/America's Natural Gas Alliance (ANGA) are incorporated by reference.

> practices at a majority of the wells. There is a clear economic incentive to capture as much of the gas as possible and where it is not possible to capture the gas, safety concerns for the personnel at the well site drive the installation of flares. It is a matter of economics and common sense—if the gas can be captured economically, it will be. If it cannot be captured economically, and it is present in sufficient quantities to represent a safety concern, it is flared.
>
> See the comments above, as they pertain to EPA's data sources and estimates.
>
> For the reasons set forth above, we have considerable doubt as to the accuracy of the national and per well estimates of methane and volatile organic compounds ("VOC") emissions for hydraulically fractured oil well completions. There is significant variation in the emissions among different well types and wells from different regions. As such, a "national estimate" will not necessarily be representative of wells from a particular region (and, in fact, would be representative only by chance).
>
> . . .
>
> As to factors that influence emissions, there are numerous factors that were not discussed in the White Papers. Most importantly, the White Papers do not adequately address the complex nature of what EPA terms "co-produced" wells, where both oil and gas are produced. Such wells are difficult to classify in terms of how any given well will behave in a wide variety of geologic formations and basins. In addition, EPA does not discuss the well-established fact that nearly all oil wells that produce appreciable amounts of gas are controlled by a combustion device for safety reasons. As mentioned above, the existing economic and safety incentives result in a majority of these wells being "controlled"—whether by a REC or combustion device. In fact, a survey submitted as part of the docket for NSPS Subpart OOOO was conducted by AXPC/ANGA member companies that showed that greater than 90% of wells were controlled prior to the rulemaking. Comment submitted by Amy Farrell, Vice President of Regulatory Affairs, America's Natural Gas Alliance (ANGA) and Bruce Thompson, President, American Exploration and Petroleum Council (AXPC); EPA-HQ-OAR-2010-0505-4241. A similar Texas Energy Alliance survey had comparable results, again supporting the position that further EPA requirements mandating REC/flares are not necessary.[49]

In the TSD for the proposed Subpart OOOOa, EPA continues to claim ignorance as to the extent state and local regulations require well completions and claim an arbitrarily low assumption that only 7 percent of completions are controlled in the absence of federal regulations.[50] This

[49] *Id.* [internal citations omitted]

[50] TSD at 22.

arbitrarily low assumption skews EPA's cost-effectiveness and takes "credit" for activities the industry is doing on its own.

D. Pneumatic Pumps

IPAA/AXPC's primary concern with the proposed requirements for pneumatic pumps is that EPA has overestimated the ease (and thus the cost) of sending captured gas to an existing combustion device. It is not as simple as plumbing a line from the pump to the control device. The intermittent nature of the gas flow and low pressures can create serious safety and operational difficulties if not appropriately designed along with significantly increasing engineering costs associated with the closed vent system upgrades. The difference between the amount of gas being vented from a storage tank and the amount of gas coming from a pneumatic pump is large, and designing a closed vent system to properly account for this pressure differential would be exceedingly difficult and costly. To meet the needs of both components, the final design would likely have the potential to increase emissions (such as being forced to use a small compressor or being forced to set thief hatches at different pressures that in turn cause more emission events from the tanks) than if the pump was vented directly to the atmosphere. The volume of gas to be captured from pneumatic pumps is relatively small, and when EPA more accurately reflects the cost associated with capturing the gas and routing it to an existing control device, IPAA/AXPC questions whether the proposed controls will be cost-effective. If EPA persists with its proposed controls on pneumatic pumps, it should clarify the definition of an "affected facility" and the interplay with reporting requirements. "Affected facility" should mean only new or modified continuous high-bleed pumps and specifically exclude low-bleed pumps (< 6 scfh). Since low-bleed pumps would not be considered an "affected facility," it is assumed they would not be subject to the reporting requirements for high-bleed pneumatic pumps. IPAA/AXPC requests confirmation of its reading of the reporting requirements.

The applicability of EPA's proposed regulations turns on whether a control device is already present at the site. EPA's regulations and preamble are silent as to whether the existing control device is already subject to NSPS and therefore an affected facility. To the extent the existing combustion device is not an affected facility, Subpart OOOOa should be clarified that existing, non-affected facility combustion devices should not become subject to NSPS simply because a new pneumatic pump is installed or an existing pump is modified. If EPA intends to pull in the existing control device and make it an affected facility, EPA must revise its cost-effective analysis to account for the additional costs associated with "converting" the existing control device to an affected facility.

E. Compressors

IPAA/AXPC supports EPA's indication that the compressor rules promulgated under Subpart OOOO and proposed Subpart OOOOa do not apply to compressors at the wellsite. IPAA/AXPC interprets the proposed CTG for compressors as essentially the same as that proposed in Subpart OOOOa, yet the CTG indicate the regulations would apply to compressors "between the wellhead and point of custody transfer."[51] This language seems inconsistent with the concept that compressors at the well site are not subject to Subpart OOOO or the proposed Subpart OOOOa. IPAA/AXPC requests clarification. Similarly, IPAA/AXPC requests clarification on whether compressors at well sites are subject to LDAR requirements. Finally, in response to EPA's specific request, IPAA/AXPC suggests the fugitive emissions requirements at compressor stations should apply only to the fugitive sources that are connected to the added or modified compressor.

F. Liquids Unloading

IPAA/AXPC supports EPA's conclusion that it does not have sufficient information to propose standards for liquids unloading. IPAA and WEA filed extensive comments on EPA's liquids unloading White Paper on June 16, 2014.[52] The numerous issues raised by IPAA/WEA have not been adequately addressed and continue to be the basis for IPAA/AXPC's position that controls aimed at reducing emissions from liquids unloading vary greatly based on numerous factors that make it difficult if not impossible to promulgate a cost-effective NSPS. IPAA/AXPC incorporates by reference these comments in their entirety regardless of topic. Nonetheless, certain portions of IPAA/WEA's comments on liquids unloading warrant repeating:

> The industry has a strong economic incentive to minimize venting episodes. Indeed, what EPA views as a pollutant is generally viewed by industry as a salable product and thus industry has an economic incentive to capture as much of the gas as possible. Unfortunately, it is not always possible to unload without venting—sometimes for safety reasons and sometimes for technological reasons. The limitations on the ability to minimize venting are difficult to predict and largely well-specific.
>
> Although the challenges associated with liquids unloading are equally prevalent among horizontal and vertical wells, the ability to recover the cost of "controls" will most likely disproportionately affect smaller operators, marginal wells and vertical wells. Nowhere in the charge questions or White Paper does EPA attempt to address the potential for such disproportionate economic impacts to result from a "one size fits all" approach to minimizing emissions during liquids unloading. The need to unload liquids depends primarily on reservoir pressure, liquid/gas ratio, and surface operating pressure; the most appropriate technology used to unload will depend on the producing formation, site equipment and logistics, and other considerations. There is a wide variety of reservoir properties across and within basins, and flexibility is critical in the continued production of these wells.

[51] U.S. Environmental Protection Agency, Control Techniques Guidelines for the Oil and Natural Gas Industry (Draft), (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.

[52] Comments of the Independent Petroleum Association of America and Western Energy Alliance on White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector per the Climate Action Plan Strategy to Reduce Methane Emissions (June 16, 2014).

As a general matter, the national estimates of methane emissions based on EPA's Greenhouse Gas Reporting are overstated, over-reported and dated at this point. The 2012 API/ANGA study included in the White Paper indicates as much and concludes that EPA's Greenhouse Gas Inventory was overestimated by orders of magnitude. More source specific data—i.e., data specifically focused on liquids unloading—is needed before conclusions should be drawn as to this subsector's contribution to methane emissions from the broader oil and natural gas sector.

The formulas used by EPA to calculate the gas volumes vented during unloading events estimates that the entire well column is vented during an event. The reason for the unload is because fluid is sitting in this column, taking up this space, and resulting in an overestimation of emissions. Additionally, the formulas utilize only a casing diameter for wells without plunger lifts (and tubing diameter for wells with a lift). Most wells are generally equipped with production tubing strings in an effort to increase the velocity of the gas and liquids and reduce the potential for liquid [un]loading problems. When these tubing strings are in place, gas volumes vented during unloading events would be from the casing-tubing annulus (area between the outside of the tubing and the inside of the well's casing) and not from the entire volume of the well's casing. This is not accounted for in many of the estimates.

In addition, the formulas used by EPA assume that gas is being vented for any well liquid unload lasting longer than one hour (or 30 minutes for unloads that are plunger lift assisted). During the liquid unloading process, there is usually an initial release of gas followed by a period of time where operators are waiting for the liquid to travel up the well bore and nothing is being released from the well; this can happen for only a few minutes or up to several hours. The formulas assume that any duration longer than one hour is continually venting at a rate equal to the production rate of gas when in fact no gas is being vented, significantly overestimating the emissions from these activities.

Factors influencing regional differences in VOC and methane emissions are a complex set of variables that include temperature, pressure, hydrocarbon composition of the oil and gas within the production formation, gas to liquid ratio, well configuration, well depth and surface conditions at the time of the unloading event. The factors that influence the frequency and duration of liquids unloading include those listed in the previous sentence, and the solution for each well and/or application is based on engineering calculations and judgment and is intrinsically well-specific. Production engineers run models to determine the proper design and operating parameters. The numerous factors and inability to generalize even by formation make it difficult to predict which wells will be more susceptible to high levels of emissions associated with liquids unloading.

The need for liquids unloading is not based on a strict set of parameters or rules. It is based on a complex set of variables—primarily reservoir pressure, but also including (but not limited to) gas to oil ratio, geologic formation types, and age of well. In addition to geological factors, technology-based factors include (a) large or no production tubing strings installed, (b) wells with high sales line pressure and no compression equipment installed at the surface, and (c) wells not equipped with artificial lift equipment such as gas lift mandrels/valves, plunger lift, rod pump, etc. Regarding the type of well, horizontal or hydraulically fractured wells are no more likely than vertical or non-hydraulically fractured wells to develop liquids [un]loading problems. It is not only a problem for wells further down their decline curve.

Simply put, one cannot generalize—there is no particular pattern or predictable model that would forecast which well types are prone to having liquids [un]loading problems. It is the inability to generalize that makes each well unique and requires a case-by-case analysis to address a liquid [un]loading problem. That said, there are some trends—the highest tendency are deeper wells with high liquid to gas ratios and low bottom hole pressure. Because the reservoir pressure does decline over time, liquid [un]loadings are more prevalent in older wells. Wells drilled and completed in formations drained by previous production may experience [un]loading problems more quickly. All wells with liquid saturations above irreducible levels will develop liquid [un]loading conditions.

The cost of the technologies varies and what will constitute a cost-effective technology will vary from well to well. For example with plunger lifts, the capital, installation, and startup cost is an exponential costing issue based on ever increasing depth of the well (e.g., the cost of a 11,000 to 12,000 foot well might approximate $25,000 to $30,000 for certain operations in East Texas whereas a 1000 foot well may only be $2000 or $3000). Also related to plunger lifts, a "smart technology" cost is dependent on many variables such as well density and availability of a communication network. The communication network for 400 densely spaced wells can easily cost approximately $4 million dollars (average of $10,000/well before adding the cost of the smart controls themselves). The EPA's high range of $18,000/well is not necessarily "high" for many situations. As to artificial lifts, the costs are substantially more. One member indicated capital and installation costs for 11,000 -12,000 foot wells are in the range of $150,000 per well -- much higher than EPA's estimates. Again, the depth of the well influences the costs figures and it is difficult and inappropriate to generalize. The best solution to the liquids unloading problem is a case-by-case decision based on the engineering judgment of the operators.

. . .

As noted above, the feasibility of the use of artificial lift systems is generally site-specific and therefore it is difficult to generalize. Artificial lift systems are just one of the available "tools" or technologies to extend the useful life of a well and are utilized where cost-effective. That said, they tend to be cost-prohibitive on deeper low production gas wells and work best on shallow wells

> capable of setting a pump/plunger/gas lift below the bottom perforations. Some characteristics that discourage the use of artificial lift include deep formations, corrosive production fluids, wells with high scaling tendency, and deviated wellbores. The feasibility of artificial lifts must be assessed according to the conditions of the individual well. One size does not fit all.
>
> In certain situations, gas wells with liquid content that are unloaded are capable of being controlled with flares attached to the tank vents at the production battery. In others, the high pressures in certain regions make routing blowdowns to tanks and flares extremely unsafe. Even wells that are blown down can sometimes be vented through tanks that are controlled in many cases by flares. The capability to do this, however, depends greatly on the conditions of the well bore and the equipment used to control (tanks, flares, etc.) These flares and the associated tanks/tank vents are not specifically designed to accommodate liquids unloading. Regarding the use of flares specifically for liquids unloading events, there are several design and operational issues: (1) liquids unloading are slug flow events that are inconsistent in both gas volumes and quality, (2) consequently, designing a flare for the wide range of operating conditions is challenging, (3) additional equipment may be required to prevent liquids from reaching the flare (separators, etc.), and (4) the intermittent nature of these events is another challenging design condition especially in avoiding smoking conditions, etc. To the extent that EPA contemplates a continuous flare to minimize emissions from these intermittent events, the negative externalities associated with the carbon dioxide emissions from the pilot should be factored into any analysis. To accommodate the operational issues associated with flares and associated equipment designed to specifically address liquids unloading, they would need to be relatively large which could present safety hazards and create local permitting issues.[53]

EPA's proposed Subpart OOOOa seems to leave the door open for potential regulation of emissions associated with liquids unloading and requested comment on the issue. IPAA/AXPC supports EPA's decision to not propose federal standards. The issues outlined above have not been adequately addressed by EPA and remain largely unaddressed.

G. Miscellaneous Requests for Input

- EPA requested input on "pressure-assisted flares." IPAA/AXPC is not entirely clear what EPA is referring to as pressure-assisted flares. To the extent IPAA/AXPC understands the type of flare EPA is referring to, IPAA/AXPC does not believe there is any reason to treat these flares differently than any other flare. Or stated slightly differently, pressure-assisted flares should be treated as any other flare subject to the Subpart OOOO and proposed Subpart OOOOa regulations

[53] *Id.*

- IPAA/AXPC supports a clarification that the storage vessel provisions do not apply to large (e.g., 25,000 bbls or more) tanks used for water recycling, as they have very low emissions but might trigger the 6-ton threshold because of size and volume of throughput. EPA's recognition that this water has very low emissions calls into question whether the smaller "storage vessels" that hold the same type of water, just smaller quantities, should be an affected facility.
- IPAA/AXPC does not support EPA's concepts of independent third-party verification, fugitive emissions verification, and "electronic reporting and transparency" as described as part of EPA's Next Generation Compliance and Rule Effectiveness. As an initial matter, companies should be allowed to verify issues internally. EPA's concept of utilizing certified reviewers would pose a significant problem for the industry in terms of not having enough qualified individuals to conduct the review. Eventually the market would adjust, but in the short term there would be a shortage. EPA's concept would create a problem in an attempt to solve an "issue" that currently does not exist. Finally, industry does not support a continuous parametric monitoring system since this would result in significant costs to companies that do not have supervisory control and data acquisition (SCADA) capabilities and would another add link in the system that could fail. A simpler and better solution would be to require all thief hatch vents to be set at a pressure above that of the main ventline.

V. Control Technique Guidelines for Ozone Nonattainment Areas

Clearly, the CAA provides direction to EPA and states that requires the use of RACM in Ozone nonattainment areas to manage emissions from existing sources. However, EPA's presentation of the CTG for oil and natural gas production facilities fails to provide a technological analysis based on the fundamental basis for RACM. Instead, it arbitrarily applies the new source BSER requirements to existing sources without any realistic analysis of whether these technologies are reasonably available and applicable as RACM. Moreover, as IPAA/AXPC demonstrated earlier in these comments, the differences between the oil and natural gas production industry and other industry segments requires a recognition that there are significant differences across the industry in the size and scope of operations that dramatically impact the economic implications of controls. The CTG proposals largely ignore this reality. Any CTG for oil and natural gas production facilities needs to provide an application threshold that excludes marginal oil and natural gas wells. Finally, with the revision to the NAAQS for Ozone, new areas – many of which are rural in nature – will be subjected to the RACM created by the proposed CTG. Without the appropriate recognition of the broad diversity of the oil and natural gas production industry and the need for the CTG to be based on appropriate existing source technologies, serious adverse impacts on American production could result. Not only has EPA failed to address this issue in the CTG proposal, EPA's own assessment of the nation's ability to attain the Ozone NAAQS demonstrates that this CTG is both unnecessary and counterproductive.

Consequently, IPAA/AXPC requests withdrawal of the current CTG proposal until EPA can address its serious shortcomings and determine whether a broad CTG proposal is appropriate as a RACM approach for oil and natural gas production facilities.

Following is a detailed discussion of the basis for IPAA/AXPC's opposition to the current CTG proposal and reasons why it should be withdrawn.

In its Federal Register notice regarding the *Release of Draft Control Technique Guidelines for the Oil and Natural Gas Industry*, EPA provides a pertinent description of the RACM process:

> Section 172(c)(1) of the Clean Air Act (CAA) provides that State Implementation Plans (SIPs) for nonattainment areas must include ''reasonably available control measures'', including ''reasonably available control technology'' (RACT), for existing sources of emissions. Section 182(b)(2)(A)of the CAA requires that for Moderate Ozone nonattainment areas, states must revise their SIPs to include RACT for each category of VOC sources covered by a CTG document issued between November 15, 1990, and the date of attainment. CAA section 182(c) through (e) applies this requirement to States with ozone nonattainment areas classified as Serious, Severe and Extreme.
>
> The CAA also imposes the same requirement on States in ozone transport regions (OTR). Specifically, CAA Section 184(b) provides that states in the Ozone Transport Region (OTR) must revise their SIPs to implement RACT with respect to all sources of VOCs in the state covered by a CTG issued before or after November 15, 1990. CAA section 184(a) establishes a single OTR comprised of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont and the Consolidated Metropolitan Statistical Area (CMSA) that includes the District of Columbia.
>
> The EPA defines RACT as ''the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility'' (44 FR 53761, September 17, 1979).[54]

While this description is accurate, EPA wholly fails to meet the test of identifying "control technology that is reasonably available considering technological and economic feasibility."[55]

To understand EPA's failure, it is essential to expand our earlier discussion of the nature of the oil and natural gas production industry. As described earlier, the oil and natural gas production industry differs from other industries because of the inherent reality that its production is not constant. Instead, because of geological realities, production from most oil and

[54] Release of Draft Control Techniques Guidelines for the Oil and Natural Gas Industry, 80 Fed. Reg. 56,577, 56,578 (Sept. 18, 2015).

[55] *Id.*

natural gas wells peaks at or near its earliest stages of full production. In essence, once the reservoir is opened, the contained pressure in the reservoir forces oil and natural gas through the well bore to the surface. But, this pressure also begins to diminish and with it the flow rate of the well. While various techniques are available depending on the type of formation to improve production, these actions adjust the rate of decline; they do not return the well to its original productivity.

Consequently, over time, wells move from strong producers to marginal ones. In fact, marginal wells are defined in federal law as oil wells producing 15 barrels/day or less and natural gas wells producing 90 mcfd or less. While these are the thresholds, the average marginal wells produce at much lower levels – the average marginal oil well produces 2.7 barrels/day and the average marginal natural gas well produces 22 mcfd. There are business implications to this production depletion as well. As the operating costs of production increase when production decreases, companies sell less productive wells to obtain capital for reinvestment in new production. Many characterize the oil and natural gas production industry as a "food chain" industry with larger companies selling properties that do not fit their production structure to smaller companies. As a result, marginal well ownership is dominated by smaller organizations, many of which are privately held small businesses. As IPAA/AXPC previously stated, there are over 1.1 million oil and natural gas wells in the United States; approximately 760,000 are marginal wells.

Correspondingly, as production from wells decreases, the physics of emissions changes as well. With less pressure in the well bore, there is less pressure driving emissions to the atmosphere from operating equipment. Even more telling, the most recent research efforts such as those by the University of Texas' Center for Energy and Environmental Resources demonstrate that emissions at oil and natural gas production operations are dominated by a small percentage of sources. Moreover, experience is indicating that when these sources are corrected and maintained, emissions reductions are sustained for long time periods.

Set against this pattern of industry structure and experience, EPA has failed to create a record that demonstrates it made a thoughtful analysis of the technologies it is proposing in the CTG as RACT – particularly in the context of considering technological and economic feasibility. Instead, EPA has arbitrarily applied the BSER technologies in Subpart OOOO and proposed to do so in Subpart OOOOa as they relate to new sources in the context of existing sources. In doing so, EPA fails to appropriately adjust the economic analysis from the NSPS materials to reflect the different circumstance of existing operations.

Among the key factors that EPA understates is the need to focus these regulations on VOC emissions. Because these CTG address VOC emissions, their cost effectiveness and technological appropriateness must be evaluated with regard to their impact on VOC emissions. For example, EPA bases much of its cost-effectiveness determinations on average VOC emissions, but RACT needs to be considered by each state for each nonattainment area. Different oil and natural gas formations produce different vapor compositions including significantly different fractions of VOCs in the vapor. Correspondingly, for the same cost, cost effectiveness will change; it will become less cost-effective as the VOC concentration diminishes.

Similarly, EPA bases much of its analysis on "model" facilities, but facilities differ depending on the nature of their operations. While EPA's draft CTG proposal recommends that facilities with only a wellhead should not be included in its fugitive emissions CTG, it should similarly recognize that facilities with fewer components than the EPA model facility need to be evaluated based on their actual structure rather than presumed to be cost-effectively controlled under the CTG.

These issues become more compelling when the CTG affect marginal oil and natural gas wells. EPA partly recognizes this reality by stating in the context of its fugitive emissions proposed CTG:

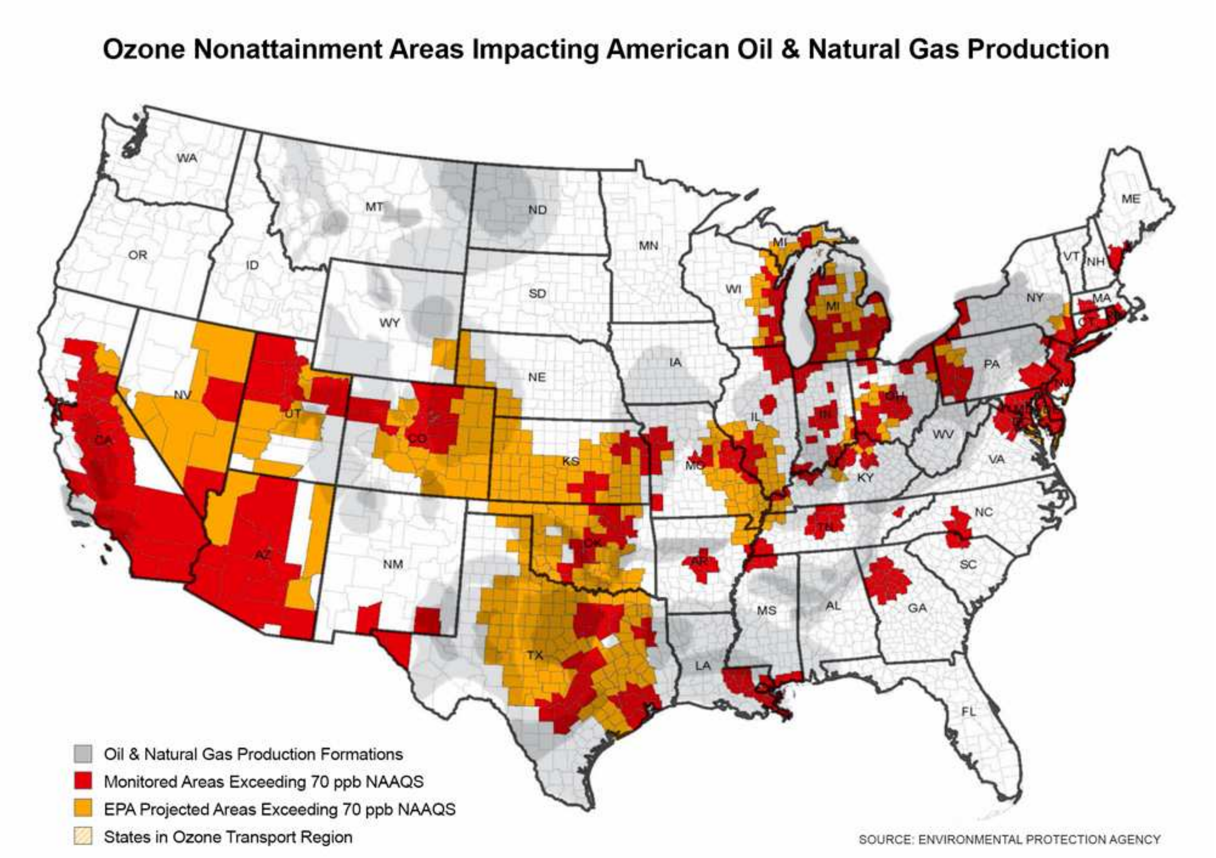
> For purposes of this guideline, the emissions and programs to control emissions discussed herein would apply to the collection of fugitive emissions components at a well site with an average production of greater than 15 barrel equivalents per well per day (15 barrel equivalents), and the collection of fugitive emissions components at compressor stations in the production segment. It is our understanding that fugitive emissions at a well site with low production wells are inherently low and that many well sites are owned and operated by small businesses. We are concerned about the burden of the fugitive emissions recommendation on small businesses, in particular where there is little emission reduction to be achieved.[56]

This recognition is entirely appropriate and accurate. However, it needs to apply to all of the CTG. Marginal wells are the most vulnerable U.S. production operations – particularly at the current oil and natural gas commodity prices that are well below the prices used by EPA in its cost-effectiveness analyses. Yet, these wells continue to provide a significant portion of American production. Additionally, the CTG should provide that status as a marginal well qualifies for an off ramp from continuing application of the regulations. That is, when a well's production drops to the point where it is considered a marginal well, the facility would no longer be subject to the regulation.

EPA also needs to recognize that its CTG proposal coincides with its decision to lower the Ozone NAAQS. American oil and natural gas operations are located where the resources exist. Unlike manufacturing facilities, they cannot choose where to operate. Historically, much of America's oil and natural gas has been located in largely rural areas. Recent development of American shale resources has placed operations closer to populated areas – many of which are in Ozone nonattainment areas. However, EPA's decision to lower the Ozone NAAQS captures areas that have previously been in attainment. Since a number of these new projected nonattainment areas encompass production areas, these CTG will have a broader and more significant potential impact on U.S. production. The following map provides a perspective on the interaction between American production areas and nonattainment with the new Ozone NAAQS.

---

[56] U.S. Environmental Protection Agency, Control Techniques Guidelines for the Oin and Natural Gas Industry (Draft), (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.



While oil and natural gas production facilities have always been subject to RACM in current Ozone nonattainment areas, the CTG proposal changes the regulatory framework significantly. Part D of the CAA provides for states to impose RACM on existing stationary sources as a part of the requirements to demonstrate attainment or Reasonable Further Progress toward attainment. These RACM requirements, however, apply to stationary sources of a specific size depending on whether an Ozone nonattainment area is classified as Moderate, Serious, Severe or Extreme. Therefore, regulation of existing oil and natural gas production facilities depended both on their size and the status of the Ozone nonattainment area. The CTG proposal in general does not set emissions thresholds for its application. As such, for large or small producers, or large or small emitters, the regulatory burden will apply and will apply far more broadly.

As EPA states with regard to the proposed Subpart OOOOa, "we [EPA] believe that the industry can bear . . . and survive."[57] However, no broad analysis of the collective impact of the CTG proposal on American oil and natural gas production in the context of the revised Ozone NAAQS has been done. Such an analysis should be done for several pertinent reasons.

57 Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,629 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60).

1. Ozone has consistently been the most difficult primary NAAQS for certain areas to meet. The following figures demonstrate the reality of Ozone NAAQS nonattainment. Figure 1 presents EPA's assessment of the areas of the country that fail to meet the 1997 Ozone NAAQS of 84 ppb (8 hour). Figure 2 presents EPA's assessment of the areas of the country that will fail to meet the current Ozone NAAQS of 75 ppb (8 hour) in 2020. Figure 3 presents EPA's assessment of its revised Ozone NAAQS by 2025.

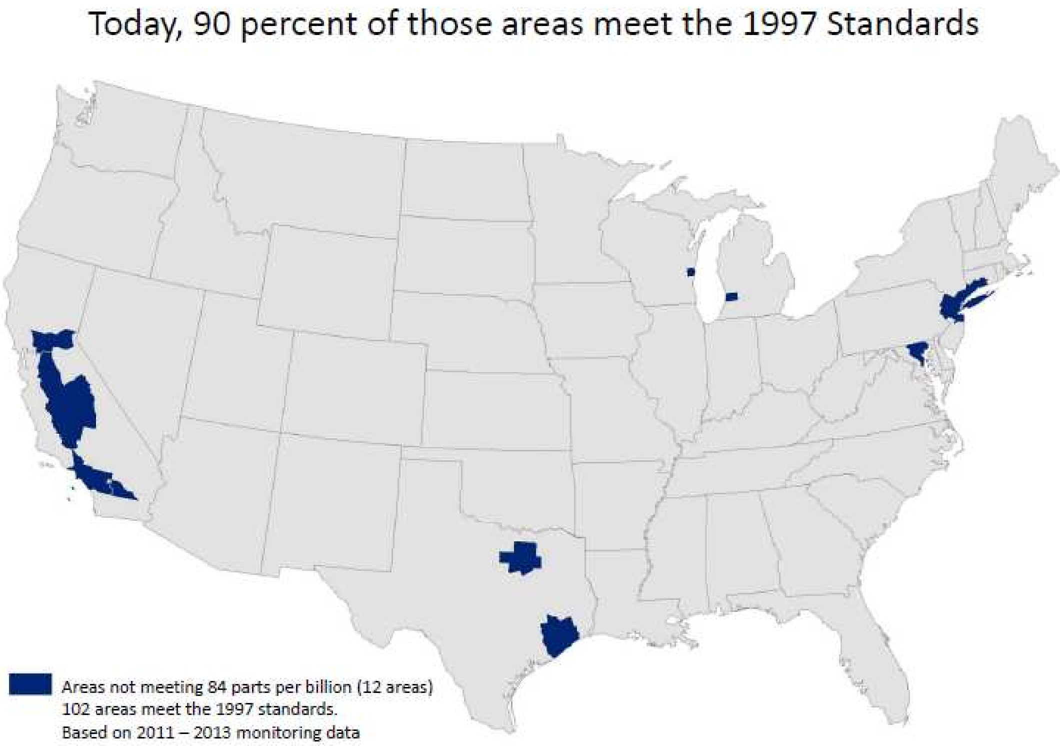


Figure 1

Source: Environmental Protection Agency

Counties with Monitors Projected to Violate the 2008 8-Hour Ozone Standard of 0.075 parts per million (ppm) in 2020

Figure 2

Source: Environmental Protection Agency

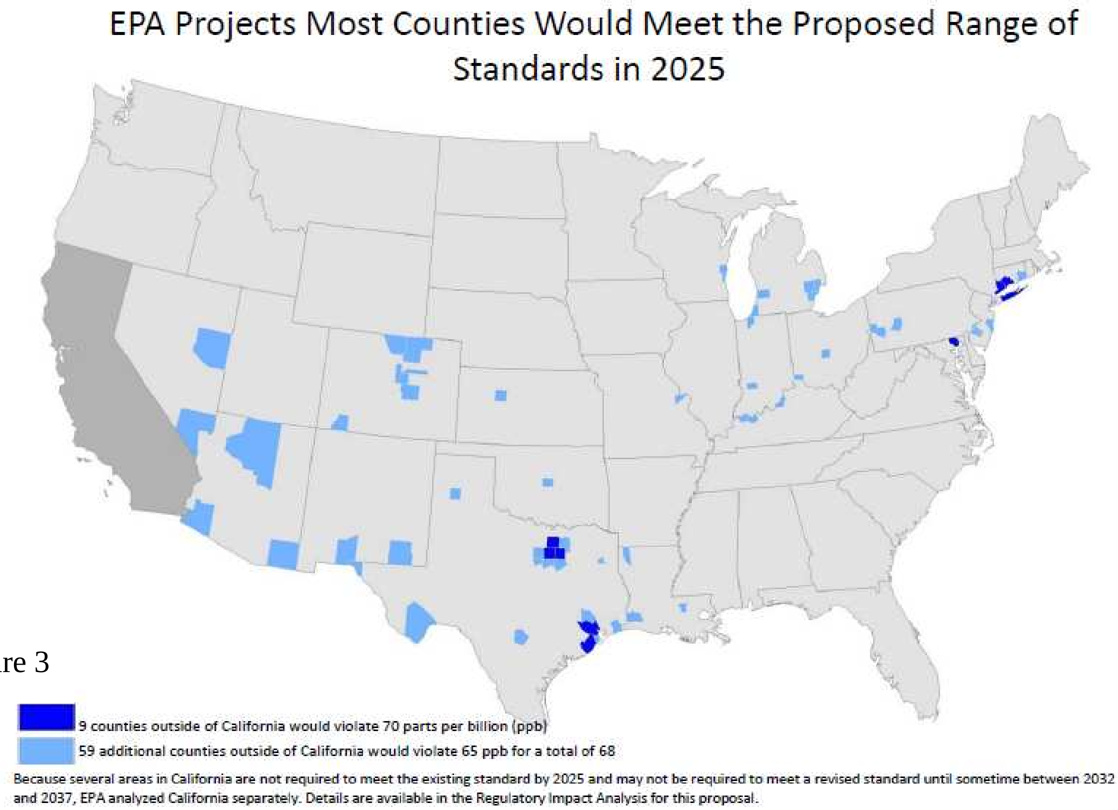


Figure 3

Source: Environmental Protection Agency

EPA's analysis shows that there are certain areas of the country that are enduring Ozone NAAQS nonattainment areas – areas that cannot meet any Ozone NAAQS that has been promulgated. The same areas that failed to meet the 1997 Ozone NAAQS and the 2008 Ozone NAAQS also will fail to meet the proposed NAAQS by 2025 and, realistically, any time until well after 2030. What this means is that EPA's claimed health benefits from the proposed NAAQS will not occur in these enduring nonattainment areas.

Equally important, the regulatory requirements in these enduring nonattainment areas will be no different under the proposed NAAQS than they are under the current NAAQS. These areas are subject to regulation under Part D – Plan Requirements for Nonattainment Areas of the CAA.

Part D was created in the 1990 CAA amendments. It creates a series of specific minimum requirements for each area in Ozone NAAQS nonattainment initially based on the area's ozone monitoring values relative to the Ozone NAAQS. Areas are classified as Marginal, Moderate, Serious, Severe and Extreme. Each classification is given a specific time frame in which to attain the Ozone NAAQS. Importantly, if an area fails to meet the NAAQS in its allotted compliance period, it is reclassified to a higher classification, required to implement the mandatory requirements and given an extension of time to meet the NAAQS. Part D requirements were initiated after the 1990 CAA amendments with attainment dates ranging from 1993 to 2010. Even with attainment date extensions, these dates have passed.

The significant impact of Part D is that perpetual nonattainment eventually produces a baseline of regulations and requirements of additional annual percentage reductions. Since these areas have been subject to Part D for 25 years, their future regulatory requirements will be the same iterative percentage reductions under the current NAAQS as the new one. Adopting the revised NAAQS will produce the same regulatory requirements for these areas as the current NAAQS.

2. EPA has stated in its support documents for its revised Ozone NAAQS that:

> Existing and proposed federal rules . . . will help states meet the proposed standards by making significant strides toward reducing ozone-forming pollution. EPA projections show the vast majority of U.S. counties with monitors would meet the proposed standards by 2025 just with the rules and programs now in place or under way.

Consequently, these national, federal requirements will essentially protect the overwhelming number of areas that would be placed in Ozone NAAQS nonattainment by the lower NAAQS without any of the local actions that would be required from such categorization.

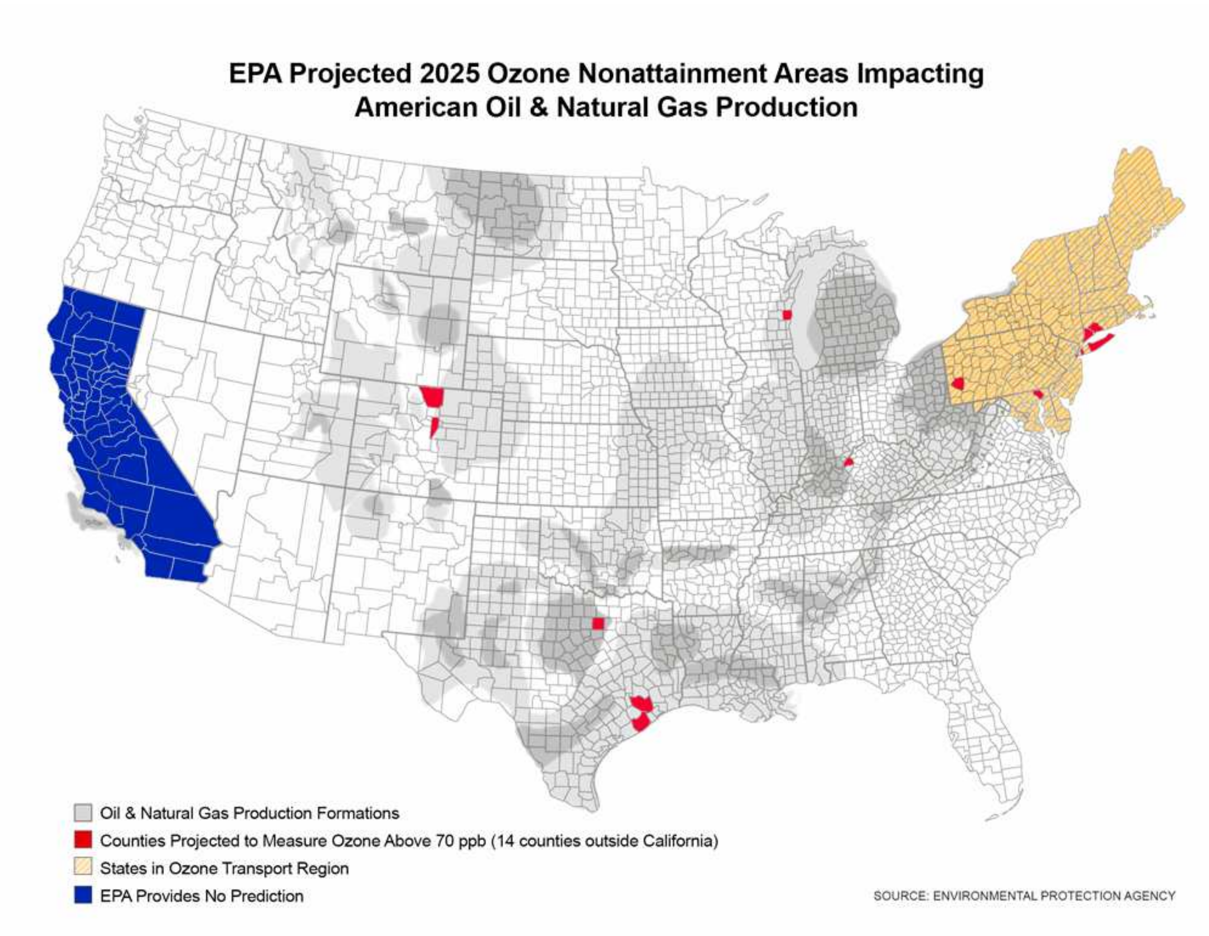
For these areas that EPA projects would reach attainment using only national, federal mandates regardless of the NAAQS, promulgating the lower NAAQS will compel them to be subject to the requirements of Part D of the CAA. Because Part D imposes a series of minimum requirements, the revised NAAQS will impose emission controls on new sources in those areas, including offsets, which will be burdensome, cost ineffective and unnecessary since EPA believes these areas would reach attainment using only its national regulations.

Once an area becomes subject to Part D, minimum requirements are mandated. For example, all new construction must not only comply with rigorous emissions controls, but all remaining emissions must be “offset” by reductions in existing emissions that are not otherwise regulated. Many of the areas that would fall into initial Ozone NAAQS nonattainment but would later attain the NAAQS are largely rural or with smaller municipalities. These areas will likely have limited existing emissions sources to regulate. These areas will face either an effective construction prohibition or the choice of shutting down existing operations that employ current workers.

3. The proposed oil and natural gas production CTG get pulled into this murky process. Enduring Ozone nonattainment areas already are a possible target for RACM requirements, but those requirements are predicated on the size of the source and

therefore not imposed without consideration of their impact on emissions and with localized consideration of cost effectiveness. For the newly captured Ozone nonattainment areas that EPA believes will meet the revised Ozone NAAQS using national, federal regulations – an assessment made without the inclusion of the proposed CTG – the application of the proposed CTG is unnecessary to reach attainment. However, because the CTG would be applied and would be applied to such small sources, these reductions are also removed from the possible pool of emissions that could be managed as a part of emissions offsets needed to build new facilities. In many of these areas, new facilities are likely new oil and natural gas wells. Consequently, the impact of the CTG would be to limit new production.

For these reasons, EPA must fully assess the energy, economic and environmental consequences of implementing the proposed CTG in the context of the revised Ozone NAAQS. IPAA/AXPC believes that EPA cannot justify the current CTG at this time. As the following graphic shows, EPA projects that only a few areas will remain in Ozone nonattainment in 2025.



This projection is based on regulatory actions taken without the proposed CTG. It demonstrates that the CTG is not essential to Ozone NAAQS attainment. Certainly, in some enduring nonattainment areas some oil and natural gas production facilities would be subject to RACM, but these decisions would be based on local conditions and the economic circumstances of the oil and natural gas production operations in those areas. Finalizing the proposed CTG would make all oil and natural gas production operations subject to the CTG without a compelling need – based on EPA's own projections of Ozone attainment – and without the opportunity to assess local need. Moreover, it would eliminate possible actions that could facilitate new construction as offsets and thereby unnecessarily threaten economic growth in these areas. If EPA finalizes an oil and natural gas production CTG without assessing all of these consequences, it can only be viewed as arbitrarily ignoring significant implications that EPA has the responsibility to address.

It is pertinent to address the methane emissions issue here, too. While this proposed oil and natural gas production CTG is written to manage VOC emissions, it has been proposed as a part of the Administration's Climate Action Plan and is partly a surrogate for methane emissions management. However, as IPAA/AXPC stated earlier in these comments, the requirements already in regulation under Subpart OOOO more than achieve the Administration's methane reduction targets for the oil and natural gas production segment of the Climate Action Plan. This CTG needs to be addressed on its merits and its consequences weighed with regard to Ozone NAAQS nonattainment.

In addition to these general concerns, IPAA/AXPC has issues associated with the specific CTG proposals.

A. Fugitive Emissions

IPAA/AXPC identified a series of specific issues in the discussion of the Subpart OOOOa proposal that apply in the CTG context as well. Here, this discussion will focus on some of those issues and raise others that arise because of its application to existing sources.

First, EPA's approach to a fugitive emissions program fails to recognize the nature of these emissions at oil and natural gas production facilities. This emissions arena is characterized by "fat tail" emissions where a few components within the facility account for the overwhelming amount of the releases. At the same time, it is an arena where the appropriate regulatory formulation is still being identified. Several states have initiated fugitive emissions programs, and each differs from the others. Clearly, it will take some time to determine the efficacy of approaches in order to assure that a cost-effective program is defined. Into the middle of this uncertainty, EPA proposes the most burdensome approach with expectations of success that are not founded on experience. Rather than bullying its way into the arena, EPA has two far better approaches it could take. One is to watch the emerging state programs and use their results to design a program. The second is to work with industry to develop voluntary initiatives that would reflect the emerging understanding of fugitive emissions patterns. IPAA/AXPC believes that EPA should withdraw its fugitive emissions proposals until more is known about the best approaches to managing them.

Second, initial experiences with state programs are revealing that once a "fat tail" source is corrected through appropriate maintenance, its emissions do not increase – at least for long periods of time. In fact, because the current state programs have been operating for a limited amount of time, some sources that have been fixed have not needed a second action. However, like its NSPS proposal, EPA creates a framework of shifting monitoring frequencies that are not justified based on experience. If EPA continues to pursue its proposal, it should rely on an annual inspection cycle to create a stable planning framework.

Third, when states have or create their own fugitive emissions programs, these programs should be considered as meeting CTG requirements.

Fourth, IPAA/AXPC supports excluding smaller facilities (e.g., marginal wells producing 15 barrels/day of oil equivalent or less) from the scope of the fugitive emissions program and believes that facilities that are initially included in any program should be excluded when their production falls below the threshold. IPAA/AXPC agrees that a fugitive emissions program should not apply to facilities with only a single wellhead. Further, EPA bases its program on a "model" facility with an expected number of components. IPAA/AXPC recommends that sites with less than the model facility components should be excluded from the fugitive emissions program.

Fifth, IPAA/AXPC believes that EPA is understating the costs of its fugitive emissions program and overstating its benefits. As IPAA/AXPC stated in discussing the NSPS proposal, EPA relies on technologies that are costly while not demonstrating those technologies are necessary to achieve benefits. For example, EPA is enamored with the use of specific OGI technologies. EPA places far too much faith that OGI can detect emissions accurately. Moreover, by using this technology, it drives compliance costs excessively. As described earlier, compelling the expenditure of more than $100,000 per FLIR camera is a burden not easily borne by existing operations where production rates are lower than new facilities in today's economic climate. EPA's proposal immediately demands confidence that the expenditure will result in substantial savings. However, nothing in EPA's CTG proposal demonstrates that it has realistically evaluated the effectiveness of this program at existing facilities. Past CTG have provided a threshold cost effectiveness test that is absent here. Rather, EPA calculates costs/ton of reduced emissions for various technologies whether they are appropriate as RACT. For example, EPA rather cavalierly discounts the costs/ton for oil wells – which exceeds $10,000/ton in all of its cases and reaches more than $25,000/ton in some – by stating "[t]he cost of control for natural gas well sites and gathering and boosting stations is considered to be reasonable."[58] Implicitly, the cost of control for oil well sites is not reasonable, but EPA proposes the same RACT requirements. IPAA/AXPC believes that oil well sites should be excluded from the CTG and that any natural gas well site program needs to be reconstructed to focus on high-emitting sources with flexibility to use more cost-effective approaches.

EPA errs in locking in current technologies, like OGI, that may well be far less cost-effective than new approaches that may arise as state programs learn from experience. As with the NSPS proposal, EPA needs to allow the development of knowledge in managing these fugitive emissions before framing a rigid and ineffective mandate.

[58] U.S. Environmental Protection Agency, Control Techniques Guidelines for the Oin and Natural Gas Industry (Draft), (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.

B. Storage Vessels

There is a vast difference between regulating new storage vessels and existing ones. Specifically, a new vessel can be designed to accommodate a vapor collection system whether it is for recovery or combustion. Once built, both the vessel and the system can be maintained to assure that they are operating effectively and safely. Because a CTG addresses existing facilities, there is no certainty that the storage vessels will be capable of accepting the equipment needed to capture vapors. Vessels deteriorate over time despite maintenance, and if the structural integrity is compromised by the additional equipment, a safety issue arises.

In this context, and more generally, EPA's cost estimates must be scrutinized. EPA suggests that vapor recovery units (VRU) or combustors can be considered RACT for vessels with emissions of 6 tons/year or more. However, if a storage vessel cannot safely operate with additional equipment, the entire vessel would have to be replaced, if replacement is even economically feasible. EPA does not consider this situation in calculating its cost effectiveness, but it should because the consequences would considerably change the determination of RACT. For example, at some facilities under current economic conditions, the cost of a new storage vessel would not be economically feasible based on the facility's production rates.

Additionally, IPAA/AXPC believes that marginal well facilities should be excluded from the scope of the CTG. Clearly, the burden of adding capture equipment – and certainly the burden of replacing storage vessels – cannot be readily borne by marginal well operations. EPA relates emissions to production rates as shown in the following table. The information contained in the table shows that marginal well operations fall well below even EPA's presumed RACT threshold of 6 tons/year. Consequently, rather than deliberate on emissions estimates, the straightforward approach to defining the scope of the storage vessel CTG would be to exclude marginal well operations. Similarly, when a facility's production levels fall to the point when it becomes a marginal well operation, it should no longer be required to operate any vapor capture system. Beyond that, there should be the opportunity – like there is in Subpart OOOO – to demonstrate that uncontrolled emissions levels are below 4 tons/year to obtain an exclusion from the storage vessel CTG.

Table 4-2. Average Oil and Condensate Production and Storage Vessel Emissions per Production Rate Bracket[13]

Production Rate Bracket (BOE/day)[a]	Oil Wells		Gas Wells	
	Average Oil Production Rate per Oil Well (bbl/day)[b]	Crude Oil Storage Vessel VOC Emissions (tpy)[c]	Average Condensate Production Rate per Gas Well (bbl/day)[b]	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 EIA. "US Total Distribution of Wells by Production Rate Bracket." http://www.eia.doe.gov/pub/oil_gas/petrosystem/us_table.html.
[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.

C. Pneumatics

The proposed CTG addresses both pneumatic controllers (regulated for new sources under Subpart OOOO) and pneumatic pumps (proposed for new source regulation under Subpart OOOOa). IPAA/AXPC believes that these requirements should not apply to marginal well facilities. In addition, EPA needs to clarify that the CTG does not apply to pneumatics with continuous emissions less than 6 scf/h.

D. Compressors

The proposed CTG addresses a subset of compressors as follows:

(a) *Centrifugal compressors*. Each centrifugal compressor, which is a single centrifugal compressor using wet seals located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.

(b) *Reciprocating compressors*. Each reciprocating compressor located between the wellhead and point of custody transfer to the natural gas transmission and storage segment. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not a source subject to VOC requirements under this rule.[59]

However, it makes no distinction based on the size of the facility. IPAA/AXPC believes that the CTG should not apply to marginal well facilities and that its application should be terminated when a facility becomes a marginal well operation.

E. Conclusion

The proposed oil and natural gas production CTG should be withdrawn. It fails to provide a technological analysis based on the fundamental basis for RACM. Instead, it arbitrarily applies the new source BSER requirements to existing sources without any realistic analysis of whether these technologies are reasonably available and applicable as RACM. It largely ignores the differences between the oil and natural gas production industry and other industry segments that require recognition of the significant differences across the industry in the size and scope of operations. These differences dramatically impact the economic implications of controls. While a portion of the CTG proposal creates an application threshold that excludes marginal oil and natural gas wells, a similar provision should apply to all of its provisions but does not. Finally, with the revision to the NAAQS for Ozone, new areas – many of which are rural in nature – will be subjected to the RACM created by the proposed CTG. Not only has EPA failed to address this issue in the CTG proposal, EPA's own assessment of the nation's ability to attain the Ozone NAAQS demonstrates that this CTG is both unnecessary and counterproductive.

VI. Comments on Source Determination Proposal

The EPA is soliciting comments on a potential revision of the process for determining the nature of a source for certain emissions units in the oil and natural gas sector. Among these are facilities that produce oil and natural gas. The proposal addresses CAA new source permitting

---

[59] U.S. Environmental Protection Agency, Control Techniques Guidelines for the Oin and Natural Gas Industry (Draft), (Aug. 2015) *available at* http://www3.epa.gov/airquality/oilandgas/pdfs/og_ctg_draft_081815.pdf.

under the Prevention of Significant Deterioration (PSD) program, the Nonattainment New Source Review (NNSR) program, and Title V permitting program. IPAA/AXPC believes that establishing certainty regarding source determinations provides an important benefit to the permitting process. Below are a series of recommendations and comments that address IPAA/AXPC's concerns regarding the EPA proposal. However, at the outset, IPAA/AXPC would observe that, while there have been some specific issues associated with past interpretations of oil and natural gas production sources, the issue of source determination applies to all stationary sources.

Similarly, this issue of changing the structure of source determination must conform to the constraints of past interpretations. As EPA characterizes its actions on source determination in the Federal Register:

> Adhering to the statutory language in CAA section 111(a)(3), we have defined the term ''stationary source'' to mean ''any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant'' [40 CFR 52.21(b)(5); 40 CFR 51.165(a)(1)(i); 40 CFR 51.166(b)(5)]. We have then further defined the four statutory terms ''building, structure, facility, or installation'' collectively in our NSR regulations to mean ''all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control),'' where the ''same industrial grouping'' refers to the two-digit Standard Industrial Classification code [40 CFR 52.21(b)(6); 40 CFR 51.165(a)(1)(ii); 40 CFR 51.166(b)(6)]. These three regulatory factors: (1) Same industrial grouping; (2) location on contiguous or adjacent properties; and (3) under the control of the same person or persons must be evaluated on a case-by-case basis for each permitting decision.[60]

EPA needs to confirm clearly that its actions on source determination operate within this larger framework.

EPA presents two approaches to source determination. These comments focus principally on Option A – defining the source based on proximity – because IPAA/AXPC strongly opposes Option B, which includes exclusively functionally interrelated equipment.

Much of the history of the source determination question for oil and natural gas production occurred prior to the significant shift in development to shale formations and the evolution of technology that has been so successfully applied to produce those resources. These changes in the nature of oil and natural gas development alter the physical aspects of producing operations. Oil and natural gas production operations have moved from a framework where numerous vertical wells were drilled in developing a resource play to a framework where development relies on significant horizontal legs providing access to the resources. Correspondingly, a typical well site will now include numerous individual wells ranging from six

[60] Source Determination for Certain Emission Units in the Oil and Natural Gas Section, 80 Fed. Reg. 56,579, 56,580 (Sept. 18, 2015) (to be codified at 40 C.F.R. pts. 49, 51, 52, *et al.*).

to twelve to, sometimes, twenty. As a result, the concepts that drove past EPA actions to consider source determination approaches that aggregate multiple well sites together – essentially the "daisy chaining" concept the EPA seeks to avoid in this proposal – no longer reflect the industry's common practices.

Similarly important, the regulatory structure that affects oil and natural gas production has changed significantly. Since the beginning of 2015, the industry has been subjected to NSPS requirements on completions of new hydraulically fractured natural gas wells, pneumatic controllers, and storage vessels. Currently pending are proposals to regulate new hydraulically fractured oil wells, pneumatic pumps, compressors, and fugitive emissions. These regulations apply to virtually every new well site and manage the emissions. Consequently, the issue of emissions management is essentially settled, and the principle issue of the source determination rule will be the regulatory burden for the specific permitting programs of the proposals – PSD, NNSR, and Title V. Because emissions are not the driving factor in the decision, EPA should move toward limiting burdens rather than expanding them.

These factors shape our view that Option A – *Define Source Based on Proximity (Similar to the NESHAP)* – is the far better framework to address source determination. As EPA characterizes Option A:

> Under the first, and currently preferred, option for which the EPA is taking comment, the EPA proposes to define "adjacent" such that the source is similar to that in the NESHAP for this industry, Subpart HH, National Emissions Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities (40 CFR 63.760). Under this option, the "source" for oil and natural gas sector activities is presumed to be limited to the emitting activities at the surface site, and other emitting activities will be considered "adjacent" if they are proximate. Thus, under this first option, two or more surface sites must be considered as a single source if they share the same SIC code, are under common control, and are contiguous or are located within a short distance of one another.
>
> We prefer this option because we believe that a definition that centers on a surface site is familiar to the industry and the regulators because of the current NESHAP requirements, so it will streamline permitting. We also believe that a definition focused on a surface site most closely represents the common sense notion of a plant for this industry category. Surface sites that are not in close proximity to one another may be on a separate lease which may not align with the common sense notion of a single plant. In addition, we believe that this definition is consistent with Congress' intent, at least as they expressed it with regard to [hazardous air pollutants (]HAPs[)], as discussed previously.[61]

IPAA/AXPC essentially agrees with EPA's characterization and its rationale. Where IPAA/AXPC differs relates to an issue where EPA seeks specific comments – whether it is

---

[61] *Id*. at 56,586-7.

appropriate to establish a specific distance within which to consider multiple surface sites as a single source, and if so, what that distance should be. EPA is proposing a distance of a ¼ mile. IPAA/AXPC believes that EPA should, instead, adhere to the approach it has used in the NESHAP formulation. EPA should base its final factor on sites being contiguous in addition to sharing the same SIC Code and being under common control.

This approach improves on the proximity concept because it avoids picking an arbitrary distance, such as a ¼ mile. Moreover, it readily addresses another issue that EPA raises – "daisy-chaining". EPA is correct to be concerned that linking one site to another through its proximity invites the opportunity to link a third or a fourth or more sites solely on the basis of proximity. There is no value in daisy-chaining since the individual sites are each subject to the emissions management requirements under the appropriate NSPS or whatever additional regulations apply.

If, however, EPA persists in utilizing a specific distance, it is correct that some states use ¼ of a mile as a bright line to exclude needless source determinations for facilities outside that distance. However, most states then conduct a case-by-case source determination for facilities inside the ¼ mile based on proximity and the "common sense notion of a plant." Therefore, if EPA persists in utilizing a specific distance, it should follow the example of most of the oil and gas producing states and use the bright line to trigger a case-by-case source determination inside that bright line. It is also important to recognize that using an arbitrary distance raises questions of daisy-chaining, and EPA should have language either in the rule or the preamble to state that facilities should not be daisy-chained. EPA has also asked from where a specific distance should be measured. We suggest that the distance be based on the center of the new source triggering the source determination to the center of any nearby facility.

EPA should reject Option B – *Define Source To Include Exclusively Functionally Interrelated Equipment*. Option B essentially invites daisy-chaining. It creates the opportunity to link multiple facilities regardless of the distances between them. For example, as EPA states "[e]xclusive functional interrelatedness might be shown by connection via a pipeline or other means, because of the physical connection between the equipment."[62]

This characterization largely parrots the circumstances in the *Summit Petroleum Corp. v. U. S. Environmental Protection Agency*, 690 F.3d 733 (6th Cir. 2012) case. In this case, as EPA describes in its discussion of these proposals:

> In the decision, the Court said that the EPA's use of interrelatedness in determining whether sources were "adjacent" is unreasonable and contrary to the plain meaning of the term as currently used in EPA's regulations. The two judges in the majority found that the term "adjacent" was unambiguous and its plain meaning related only to physical proximity, and thus could not include

[62] *Id*. at 56,587.

> consideration of functional interrelatedness. The EPA sought rehearing of the Court's decision, but that request was denied.[63]

Why EPA would suggest moving back toward this judicially rejected approach is unfathomable. More importantly, it does not create any environmental benefits, because, as stated above, the existence of the current and proposed EPA oil and natural gas production regulatory requirements would apply to the separate facilities. Option B would only create substantially expanded regulatory burdens.

In conclusion, IPAA/AXPC believes that EPA's appropriate choice is a modified Option A relying on the use of a contiguous border to aggregate sources if aggregation is appropriate. To facilitate clarity on this issue, IPAA/AXPC suggests adding the following definition where appropriate in the Code of Federal Regulations:

> "Contiguous or adjacent properties" mean surface areas with an affixed building, structure, facility or installation including permanently graded or cleared areas for such building, structure, facility or installation, that share an edge/boundary, physically touch, and are adjoining or physically abutting.

CONCLUSION

IPAA/AXPC values the opportunity to comment on the above referenced regulatory proposals. The oil and natural gas production industry has worked closely with EPA over the past decade to promulgate reasonable, cost-effective regulations on air emissions. While industry objected to various aspects of the Subpart OOOO regulations controlling VOC emissions from various sources within the oil and natural gas sector, through the administrative reconsideration process and revisions to Subpart OOOO, many of the issues have been addressed without protracted and costly litigation. The proposed Subpart OOOOa and CTG regulations seem to represent a departure from a willingness on the part of this Administration to promulgate reasonable, cost-effective, and most importantly, needed regulations.

EPA's pollutant of concern is methane. Unlike other "pollutants" and other industrial "products," methane is not treated as a pollutant in the oil and natural gas industry – it is a valuable product. Unlike other industries, market forces are constantly at work to minimize what EPA views as a pollutant and our industry views as a product. The fact methane is a primary constituent of what this industry produces explains, in large part, why emissions from the exploration and production segment of the oil and natural gas sector have gone down while production has gone up (see Section I above). In reality, most of the reductions are a function of voluntary measures by producers to retain/capture methane or state regulatory programs where oil and natural gas production has increased dramatically in the past decade.

A central theme to IPAA/AXPC's comments is that the proposed Subpart OOOOa regulations are unnecessary and the CTG proposed regulations are, at best, premature. The

---

[63] *Id.* at 56,584.

EPA's legal foundation and basis for the proposed Subpart OOOOa and CTG regulations are dubious and invite legal challenge. It is arbitrary and capricious for EPA to base its proposed methane regulations (NSPS and CTG) on a model that predicts the social cost of methane. The irony is that EPA can accomplish a majority of its goals with modifications to existing regulations and attainment of the current Ozone NAAQS. The cost of EPA's proposed NSPS and CTG is not justified.

A. Proposed Methane New Source Performance Standards Summary Comments

- Regulations cannot be based on what EPA "believe[s]" "the industry can bear . . . and survive."[64]
- EPA's "consistency," patchwork "endangerment finding," and global warming concerns do not warrant direct regulation of methane emissions from the oil and natural gas sector.
- EPA's failure to evaluate the cost associated with the potential regulation of existing sources under Section 111(d) is arbitrary and capricious.
- States (and operations within those states) should not be penalized for taking early action to address emissions from the oil and natural gas sector, i.e., compliance with essentially equivalent state programs should be deemed compliance with the finalized Subpart OOOOa regulations.
- EPA's focus on fugitive emissions at well sites and compressor stations is premature and not supported by reliable cost/benefit data.
    - EPA's request for input and comment on numerous aspects of the proposed regulations is indicative of an issue that regulators and industry are still learning to address.
    - The "corporate fugitive management program" is a logical way to address the issue, but regulators and companies need time to determine what such a program should look like.
    - EPA's cost-effectiveness analysis for the proposed regulatory package suffers from shortcomings on both sides of the equation: for the reasons set forth above, the costs are understated and the benefits are overstated or unsupported.
    - States with the most active shale plays are learning valuable information on how to reduce fugitive emissions. EPA should not rush to judgement and establish federal standards that will be inconsistent, duplicative and potentially unnecessary because of state efforts.
    - For the reasons stated above, EPA should not dictate a specific technology for determining "leaks." OGI may be appropriate in certain instances, but EPA's selection of one technology is arbitrary and capricious.
    - EPA's proposed approach to determining the frequency of LDAR surveys based on percentage of leaking components demonstrates its lack of understanding of the issues associated with fugitive emissions. As discussed above, EPA's

[64] Oil and Natural Gas Sector: Emission Standards for New and Modified Sources, 80 Fed. Reg. 56,593, 56,629 (Sept. 18, 2015) (to be codified at 40 C.F.R. pt. 60)

  - proposed regulations would impose significant costs on the industry with dubious environmental benefit.
  - IPAA/AXPC supports EPA's proposed exclusions but seeks clarification that the 15 boe exclusion also serves as an off ramp to reduce the burden of the proposed regulations.
- Oil well RECs are not the same as RECs at natural gas wells.
  - IPAA/AXPC questions if EPA has documented new information to justify the cost-effectiveness of RECs on oil wells. The economics and engineering limitations at oil wells are different than natural gas wells, and EPA has failed to adequately differentiate between the two and justify RECs at oil wells.
  - IPAA/AXPC supports the limited exclusions to the oil well REC requirements but suggests clarification as to the requirements associated with noncombustible gas.
- EPA's proposed regulation of pneumatic pumps fails to adequately reflect the complexity, cost, and safety issues associated with sending captured natural gas to an existing combustion device. IPAA/AXPC believes that if the costs associated with such complexity were adequately reflected, the proposed regulations would not be cost effective.
- IPAA/AXPC supports EPA's proposed regulations that indicate the compressor rules do not apply to compressors at the wellsite but requests clarification that a similar exclusion applies under the proposed CTG.

B. Proposed CTG Summary Comments

- The CTG regulations must be based on a technological analysis for RACM instead of arbitrarily transposing new source BSER requirements to existing sources.
- The CTG regulations need to recognize differences across the oil and natural gas production industry that recognize size and scope of operations.
  - Marginal oil and natural gas production facilities should be excluded from all of the CTG.
- The CTG regulations must be based on their applicability to manage VOC emissions in Ozone NAAQS nonattainment areas.
  - EPA has failed to provide justification for the CTG as necessary for Ozone NAAQS attainment and, in reality, EPA's projections of Ozone NAAQS attainment in 2025 demonstrates the CTG are not necessary.
  - Implementation of the CTG in the absence of a demonstrated need is counterproductive and unnecessarily constrains economic growth.

C. Proposed Point Source Determination Summary Comments

- EPA should adopt a Source Determination definition that adheres to the approach it has used in the NESHAP formulation. EPA should base its final factor on sites being contiguous in addition to sharing the same SIC Code and being under common control.
- EPA should reject the use of functionally related equipment as a consideration in adopting revisions to its Source Determination definition.

If EPA has any questions or concerns, please do not hesitate to contact us.

Sincerely,

Lee Fuller
Executive Vice President
Independent Petroleum Association of America

V. Bruce Thompson
President
American Exploration & Production Council

Cc: Janet McCabe, EPA
Joe Goffman, EPA
Peter Tsirigotis, EPA
David Cozzie, EPA
Bruce Moore, EPA
Cheryl Vetter, EPA
Chris Stoneman, EPA
Charlene Spells, EPA

ATTACHMENT A

ACRONYM INDEX

AAPL	American Association of Professional Landmen
AEO	Annual Energy Outlook
AESC	Association of Energy Service Companies
ANGA	America's Natural Gas Alliance
API	American Petroleum Institute
AR5	Fifth Assessment Report
AVO	audio/visual/olfactory
AWEA	American Wind Energy Association
AXPC	American Exploration and Production Council
boe	barrels of oil equivalent
BSER	best system of emission reductions
CAA or Act	Clean Air Act
CMSA	Consolidated Metropolitan Statistical Area
CTG	Control Technique Guidelines
EIA	Energy Information Administration
FLIR	forward looking infrared
GHG	Greenhouse Gas
GOR	gas-to-oil ratio
HAPs	hazardous air pollutants
IADC	International Association of Drilling Contractors
IAGC	International Association of Geophysical Contractors
IPAA	Independent Petroleum Association of America
IPCC	Intergovernmental Panel on Climate Change
LDAR	leak detection and repair

NAAQS	National Ambient Air Quality Standards
NCA3	2014 National Climate Assessment, Climate Change Impacts in the United States
NESHAP	National Emission Standards for Hazardous Air Pollutants
NGO	non-governmental organizations
NNSR	Nonattainment New Source Review
NSPS	New Source Performance Standards
NSWA	National Stripper Well Association
NYMEX	New York Mercantile Exchange
OGI	optical gas imaging
OTR	ozone transport regions
PESA	Petroleum Equipment & Services Association
PSD	Prevention of Significant Deterioration
RACM	Reasonably Available Control Measures
RACT	reasonably available control technology
RECs	reduced emissions completions
RIA	Regulatory Impact Analysis
SCADA	supervisory control and data acquisition
SCC	social cost of carbon
SC-CH_4	social cost of methane
SIC	Standard Industrial Classification
SIPs	State Implementation Plans
TSD	Technical Support Document
USG	United States Government
USGCRP	U.S. Global Change Research Program
USOGA	U.S. Oil & Gas Association

VOC	Volatile Organic Compound
VRU	vapor recovery units
WEA	Western Energy Alliance

APPENDIX B

James D. Elliott
717.791.2012
jelliott@spilmanlaw.com

December 17, 2018

The Honorable Andrew Wheeler, Acting Administrator
US Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

VIA E-MAIL AND E-FILING

Re: Environmental Protection Agency's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration at 83 Federal Register 52,056 (October 15, 2018)

Docket ID No. EPA-HQ-OAR-2017-0483

Dear Acting Administrator Wheeler:

The following Comments are submitted on the above-referenced proposed Reconsideration Rulemaking ("Reconsideration Rulemaking") on behalf of the following national and state trade associations: the Independent Petroleum Association of America ("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"), Oklahoma Independent Petroleum Association ("OIPA"), 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 Independent Producers have participated individually or through the Independent Producers in most, if not all, of the rulemakings and associated litigation since the Environmental Protection Agency ("EPA" or "Agency") proposed to revise the New Source Performance Standards ("NSPS") for the Oil and Natural Gas Sector in August 2011. 76 Fed. Reg. 52,738 (Aug. 23, 2011).[1] While many of the Independent Producers represent companies that engage in large volume hydraulic fracturing with horizontal legs, often referred to as

[1] As the EPA has opened a new docket for the Reconsideration Rulemaking, the Independent Producers incorporate by reference their Comments on the previous rulemakings associated with 40 C.F.R. Part 60, Subpart OOOO and Subpart OOOOa, including but not limited to the following documents: EPA-HQ-OAR-2010-0505-4216, EPA-HQ-OAR-2010-0505-4626, EPA-HQ-OAR-2010-0505-4752, EPA-HQ-OAR-2010-0505-4767, EPA-HQ-OAR-2010-0505-7001, EPA-HQ-OAR-2010-0505-7685, and EPA-HQ-OAR-2010-0505-12337.

unconventional drilling, a significant portion of their membership is comprised of smaller, family run operations that engage in some form of hydraulic fracturing, involving vertical wells without horizontal legs, referred to as conventional oil or gas wells. Many of the individual members constitute as small businesses under the Small Business Regulatory Enforcement Fairness Act of 1996. From the beginning of these rulemakings, the Independent Producers have tried to illustrate to the EPA that their "one-size-fits-all" approach to regulating this industry is a) inappropriate and b) disproportionally impacts conventional operations and small businesses.

Other than the proposed revisions to requirements primarily associated with low production wells, storage vessels, and alternative methods of emissions limitations ("AMEL")/emerging technology, the Independent Producers generally support the proposed revisions in the Reconsideration Rulemaking and appreciate the EPA's effort to improve and to tailor 40 C.F.R. Part 60, Subpart OOOOa ("Subpart OOOOa") to reduce the impact on the Independent Producers and their individual members while still providing more than adequate protection of the environment. The EPA should not lose sight of the simple and somewhat unique fact that what the Agency and some stakeholders view as a pollutant is the Independent Producers' product. The members of the Independent Producers have a pure economic motivation to capture every molecule of methane possible and avoid waste.

TABLE OF CONTENTS

I. EXECUTIVE SUMMARY

A. Low Production Wells

- The EPA should retain provisions for low production wells. A fugitive emissions program designed for high production wells is inappropriate for low production wells

- The EPA should provide an alternative regulatory structure for all wells that become low production wells. As wells become low production wells, they are no different from wells that begin as low production wells.

- The EPA should use the Tax Code definition of "stripper well property" as its low production well definition to avoid confusion and challenges to its definition.

- The EPA should defer any fugitive emissions regulations of low production wells until it obtains information on emissions from low production wells. Specifically, the EPA should first determine whether a low production well program is appropriate and cost-effective, and the design a program based on accurate emissions information from low production wells. The Department of Energy ("DOE") is initiating a research effort to provide specific low production well emissions information that can inform these decisions and actions.

- The EPA should exempt booster compressors associated with low production wells from the current compressor fugitive emissions program requirements and incorporate them into whatever low production well program decisions it makes.

B. Storage Vessels

- The EPA's proposal to prohibit averaging of throughput across tank batteries inappropriately ignores the relevant process unit and is inconsistent with recent consent decrees related to the design and operation of vapor control systems on storage tanks/vessels.

- The EPA's concern about the amount of storage vessels subject to Subpart OOOOa is overstated and unfounded.

- The EPA's proposal to calculate individual tank emissions based upon throughput to each individual tank is technically flawed and overly burdensome.

- The EPA's proposed revisions to what constitutes "legally and practically enforceable limits" is unnecessary and arbitrarily interferes with the Clean Air Act's ("CAA" or "Act") cooperative federalism where the states are to take the lead on implementation.

C. AMEL – Emerging Technology

- The Independent Producers support the options in the Proposed Revisions to use modeling, to test technologies in a controlled test environment, and to allow manufactures/vendors to apply for approvals.

- The EPA should allow for basin-wide approvals of emerging technology for use in complying with the leak detection and repair ("LDAR") requirements in the rule.

  - The EPA can establish clear and consistent parameters under which a technology will be able to detect methane emissions and site specific variables can be addressed in conditions required for the use of the technology.

  - Basin-wide data is necessary to determine equivalency and receive approval per CAA 111(h); basin-wide surveys that can identify potential fat-tail emission sources faster and per the EPA, higher mass emission reductions from large leaks, found earlier, are offset by some degree by smaller leaks which go undetected.

  - Common sense dictates basin-level approval; the 111(h) notice and comment process required to achieve approval is very onerous and not feasible to do for every single well site.

  - CAA Sec. 111(h)(3) does not constrain basin-wide approvals.

D. AMEL – State Equivalency

- Per cooperative federalism, the EPA should recognize the approved state programs as wholly equivalent to 40 C.F.R. Part 60, Subpart OOOO's ("Subpart OOOO") LDAR program and fully delegate the implementation of the LDAR monitoring provisions to these respective states.

- Alternatively, the EPA could require the fugitive emissions component definition from Subpart OOOOa to be used when following an alternative approved state program but the EPA should not require a duplicative administrative burden; to do so would be an undue burden with no corresponding environmental benefit.

E. Recordkeeping and Reporting

- While the Independent Producers suggest additional revisions to the frequency of the fugitive emissions monitoring surveys, the proposed changes are likely to be the most beneficial change for industry, while having no detriment to the environment.

- The EPA continues to underestimate and underappreciate the burden on the industry, especially small business, associated with recordkeeping and recording that serves no environmental benefit, *e.g.*, compliance assurance.

F. Definition of Modification

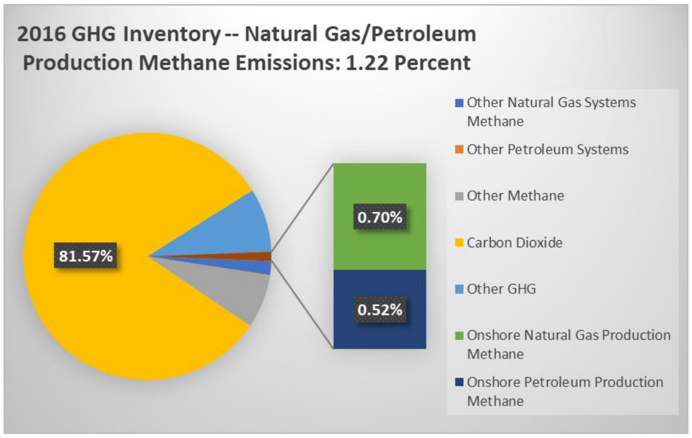
- The EPA's assumptions associated with emissions increases resulting from refracturing wells are unwarranted and unsupported.

- If the EPA persists with defining a refracture as a modification; operators should be able to demonstrate, pre-fracture, that the system is tight and therefore the refracture does not automatically constitute a modification.

II. <u>LOW PRODUCTION WELLS</u>

A. Subpart OOOOa Regulations Need to be put in Context.

The EPA has promulgated during the past decade a number of regulations that are global climate related. Some of these are active; others are being reconsidered. For the oil and natural gas production industry, the two of greatest interest are Subpart OOOO in 2012 and Subpart OOOOa in 2016. While the initial Subpart OOOO regulation was volatile organic compound ("VOC") based, it also reduces methane because VOC and methane are produced and, therefore, emitting together. Subpart OOOO addressed the larger emissions sources related to oil and natural gas production including Reduced Emissions Completions ("RECs") for hydraulically fractured natural gas wells, pneumatic controllers, and storage vessels. Its successor regulation – Subpart OOOOa – addressed a second tier of emissions including RECs for hydraulically fractured oil wells, pneumatic pumps, and fugitive emissions. The current proposed revisions to Subpart OOOOa fine tune these prior regulations to address issues where those prior actions are excessive or need a better structure. However, all of these regulations must be put in the larger context of climate – of greenhouse gases ("GHG") emissions.



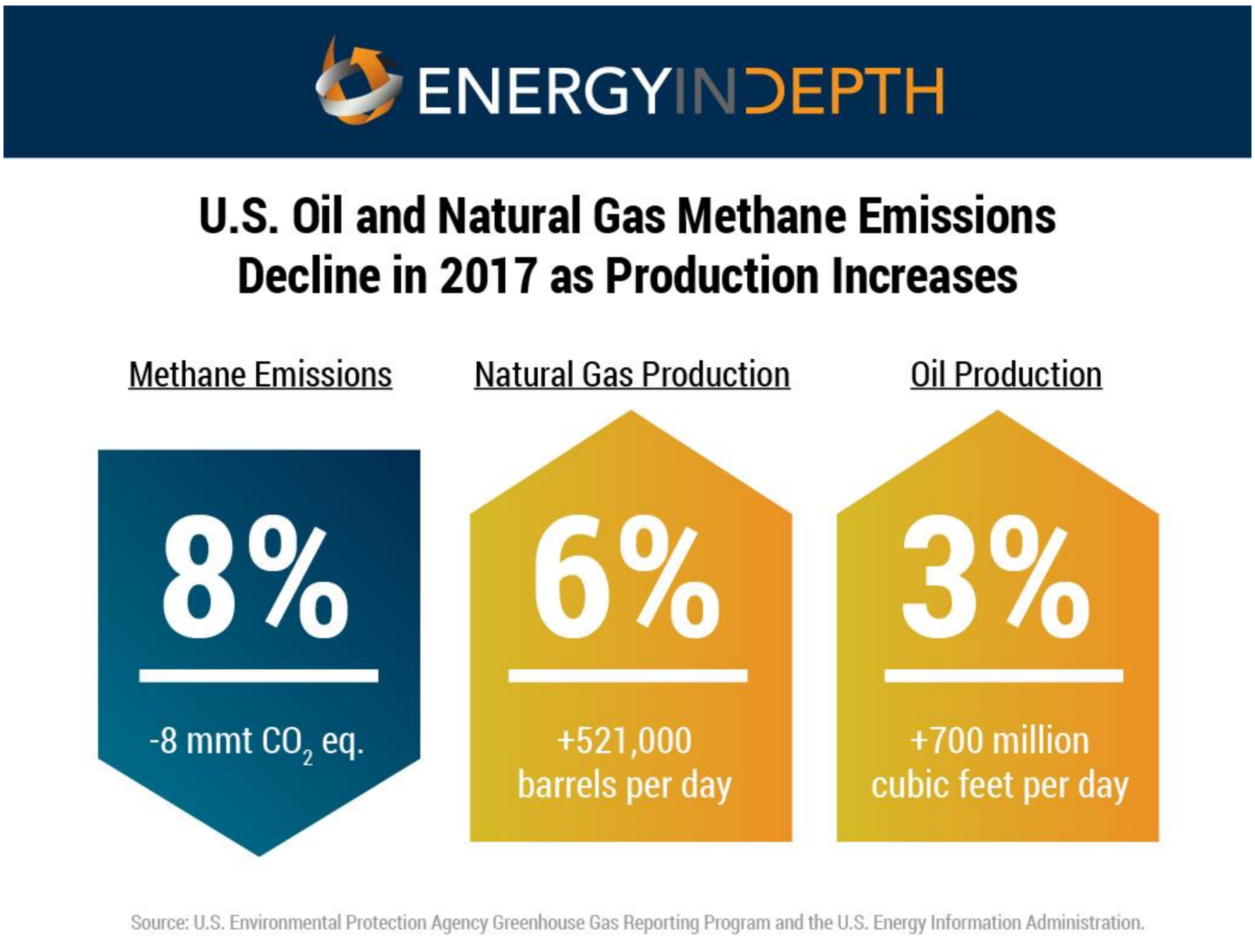
1. <u>Natural gas and oil production methane emissions are about 1.2 percent of the 2016 GHG Reporting data.</u>

According to 2016 EPA GHG Reporting data, methane emissions from oil and natural gas exploration and production are 1.22 percent of total U.S. GHG emissions. However, even these estimates may be overstating oil and natural gas production emissions. Most of the emissions calculations are based on emissions factors that come from analyses done in the mid-1990s. Newer analyses call into question a number of these emissions factors. A number of these inaccurate factors are also used in developing emissions tables for the regulatory proposals in the revisions to Subpart OOOOa. These will be addressed more specifically later in these comments.

2. <u>Production methane emissions are declining as production is increasing.</u>

More importantly, these methane emissions are declining as oil and natural gas production is increasing. From 2007 through 2016, U.S. shale gas production grew over 1,300 percent,[2] while methane emissions have declined.

More recently these trends continue, as reported in the Energy In Depth ("EID")[3] blog below. Later data supports the previous results.



New EPA data showing the United States continued to lead the world in greenhouse gas (GHG) emission reductions in 2017 – a trend largely attributable to increased natural gas use – got quite a bit of attention last week.

---

[2] U.S. Energy Information Administration, *available at* http://www.eia.gov/dnav/ng/hist/res_epg0_r5302_nus_bcfa.htm.

[3] Energy In Depth is a project funded by the Independent Petroleum Association of America, a member of the Independent Producers.

But largely overlooked was the fact that the same Greenhouse Gas Reporting Program (GHGRP) data also show that petroleum and natural gas system methane emissions from reporting facilities declined eight percent from 2016 to 2017.

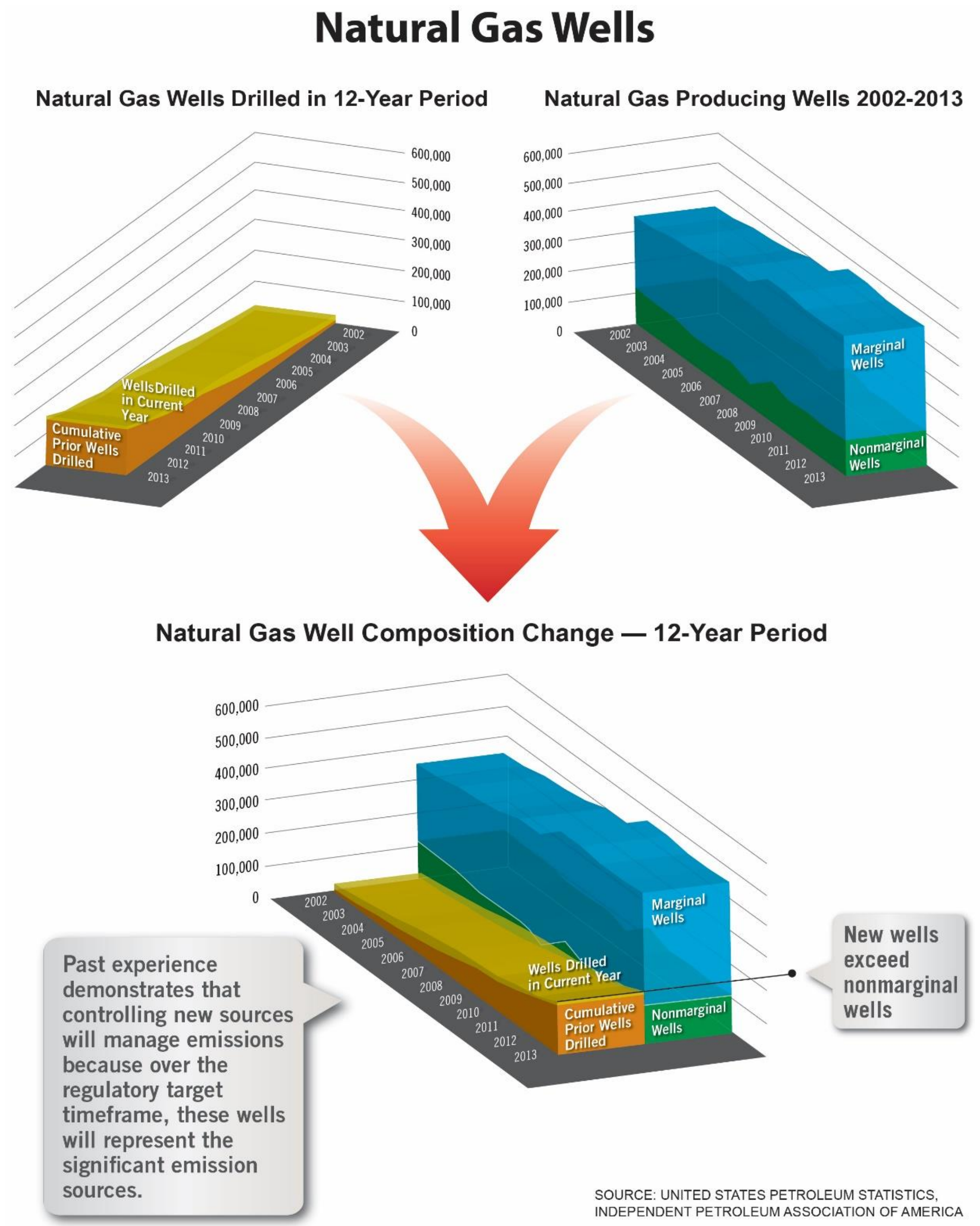
Specifically, the data show methane emissions from large oil and natural gas facilities declined eight million metric CO_2 equivalent in 2017. These reductions came at the same time oil and natural gas production increased six percent (521,000 barrels per day) and three percent (700 million cubic feet per day), respectively, from 2016 levels.

These trends prove once again that the U.S. oil and natural gas industry is effectively reducing methane emissions even as record-shattering production has made the United States the world's leading oil and gas producer.

3. **This trend will continue as new sources built since 2011 with low emissions technologies mature and displace older wells, but the regulatory proposal does not address its impact on the existing wells that would be captured in the regulations despite the declining emissions from the oil and natural gas production sector.**

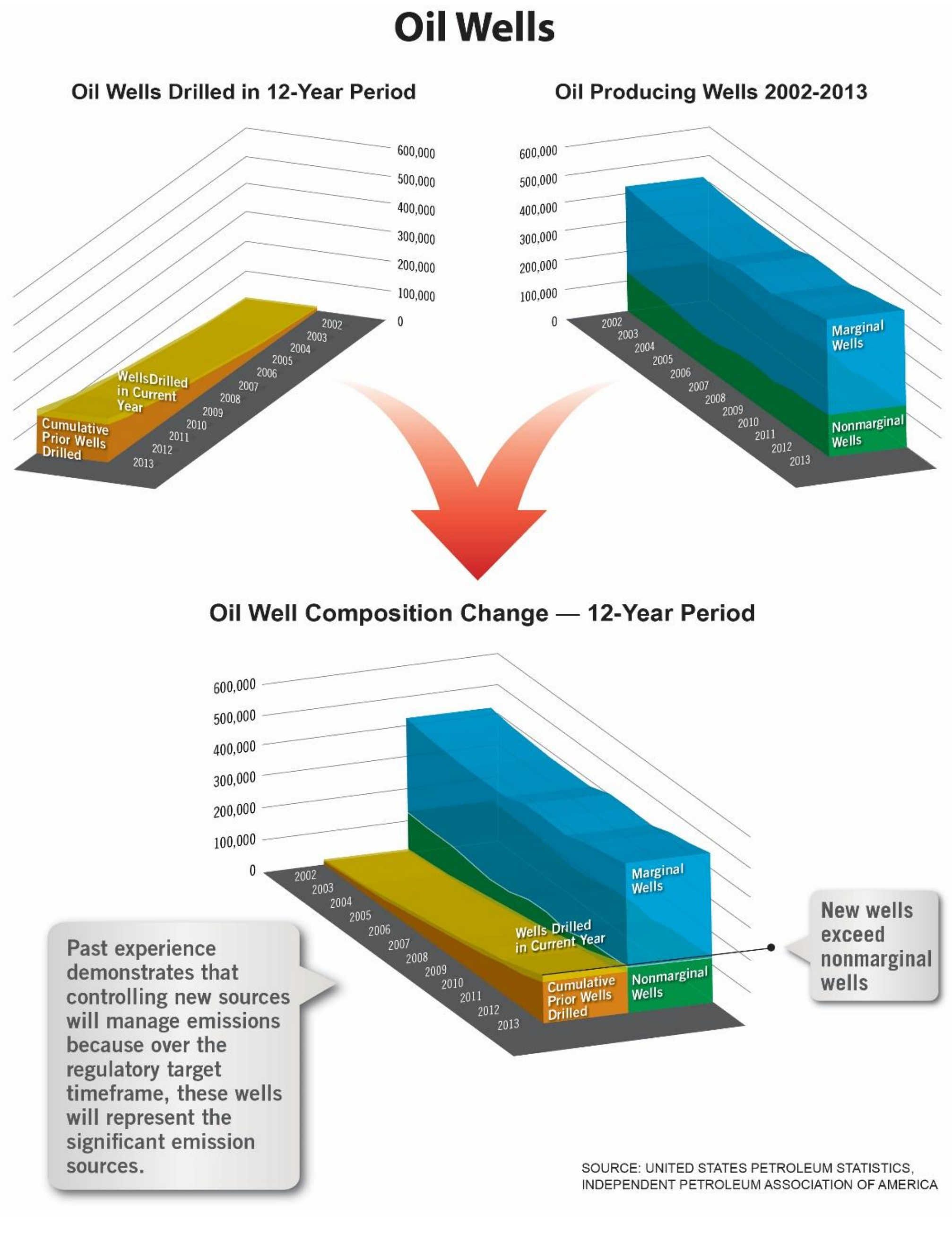
Moreover, because of the nature of oil and natural gas production, the application of controls on new sources will achieve the emissions reductions objectives without the need to create extensive existing source regulations. Oil and natural gas production operations differ from other types of manufacturing. After the period of initial production, wells begin to decline – generally referred to as the "production decline curve." And as the production of the well declines, its ability to emit VOCs and methane into the atmosphere also declines. Emissions from these older wells will be a smaller portion of the 1.22 percent of emissions, yet the EPA's decision to regulate methane directly under Section 111(b) of the CAA subjects hundreds of thousands of existing wells to regulation. The Independent Producers assert that the application of the proposed requirements to existing sources is not effective. The regulatory burden on state and federal regulators of exposing hundreds of thousands of existing sources is completely overlooked in Subpart OOOOa and the EPA was obligated to consider the cost in promulgating Subpart OOOOa and the Proposed Revisions.

The declining nature of oil and natural gas wells also differentiates the exploration and production segment of the oil and natural gas sector from other segments further downstream where emissions remain fairly constant overtime. Ultimately, the production from the "new" wells declines to the point where they become "marginal" wells or as the proposed regulations describes them, "low production" wells. These are defined as wells that produce 15 barrels/day ("B/D") of oil or less and 90 thousand cubic feet per day ("mcfd") or less of natural gas. Currently, there are over 1.1 million oil and natural gas wells in the United States; approximately 770,000 are marginal wells. However, these small individual wells account for about 10 percent of U.S. oil production and 11 percent of its natural gas production. Consequently, unlike manufacturing facilities where new facilities do not replace existing ones, in the oil and natural gas production industry, the implementation of technology on new wells will rapidly result in its application across the breadth of the industry as new wells become the predominant source of emissions for the industry. This can be understood by looking at past experience as shown in the graphs below:



As this graphic demonstrates, after 12 years, wells subject to the new source regulatory requirements will dominate the production of natural gas, and the remaining wells will be marginal wells with minimal incremental emissions beyond the emissions from sources already subject to regulation. The cost associated with reducing those incremental emissions will be greater than the cost of implementing controls on new or modified sources and will likely make many of the marginal wells uneconomic, causing them to be shut in/abandoned. The opportunity cost or value of that last production is not offset by the minimal emissions reductions achieved by regulating existing sources.

A similar pattern exists for oil wells as shown below:



While this analysis is based on past experience, if it were expanded to a 20-year period, it would show a similar trend and demonstrate that the use of new source regulations is more than adequate to address reducing methane emissions from the oil and natural gas sector, in general, and the exploration and production segment, in particular. The EPA's use of methane based regulation exposes the hundreds of thousands of existing marginal wells to regulation under

Section 111 of the CAA, and the EPA has failed to adequately account for and justify subjecting these existing exploration and production sources to such regulation.

B. The EPA Should Provide for a Low Production Well Distinction within Subpart OOOOa.

In its initial Subpart OOOOa regulatory proposal, the EPA chose to exclude low production oil and natural gas wells. The Independent Producers supported this concept because low production wells are an insignificant contribution to national methane emissions and, additionally, they cannot absorb the costs of the EPA fugitive emissions programs designed for large production wells. The economic viability of most of these wells is uncertain because of other additional state and federal requirements and low natural gas prices. However, in finalizing Subpart OOOOa, the EPA removed the low production exclusion. This is an error.

The EPA has now proposed to reinstate a low production well distinction but has not gone far enough. The proposed biennial fugitive emissions surveying for low production wells is helpful but is insufficient for three critical reasons: 1) the Independent Producers believe that with the proper studies, sampling, and testing, the low production wells will fall below reasonable emissions standards; 2) even on a biennial basis, the fugitive emissions survey requirements are not cost effective; and 3) as long as the NSPS are based on methane emissions versus emissions of VOCs, hundreds of thousands of existing wells will be exposed to unnecessary controls and costs.

1. <u>The EPA's proposed low production well provisions are inappropriate</u>.

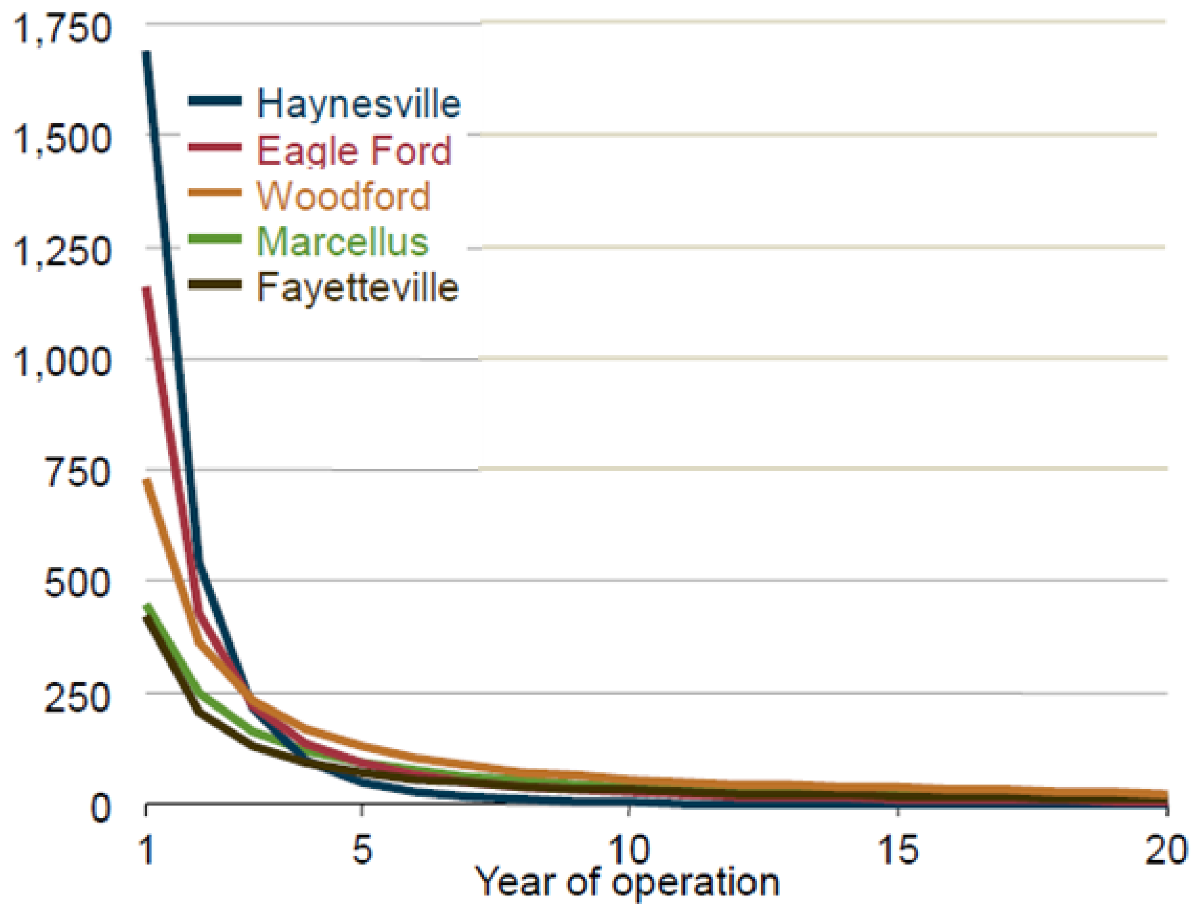
a. The EPA fails to recognize that wells ultimately become low production wells and many wells begin as low production wells. This changes the cost effectiveness of its regulations.

While Subpart OOOOa primarily addresses new sources, it fails to recognize the preeminent reality of oil and natural gas production – all wells deplete and decline in production over time. The reality of oil and natural gas well depletion has been well recognized since oil and natural gas production began. The 1940 book, <u>This Fascinating Oil Business</u>, includes this description:

> …The production of all wells in which gas is the chief expulsive force and which are produced to capacity declines rather rapidly. This decline is especially noticeable in the early stages, from the "initial production" through what is known as the "flush" period and is less noticeable after the "flush production" is gone and the well is on "settled production," but the decline continues just the same.
>
> If the well is producing at capacity the decline is quickly noticeable; if it came in at two thousand barrels a day, in six months it may be down to a thousand barrels and in a year to six hundred. If the well is allowed to produce only a part of its potential production the decline may not be noticeable for a long time; the decline in pressure will be slower, for one thing, and for another, a well allowed to produce only twenty barrels a day will probably behave much the same whether its full productive capacity is two thousand barrels or only two hundred. Sooner

> or later, however, the well will fail to make the twenty barrels or one hundred or whatever amount it has theretofore been producing, and from that time on its decline will be apparent. Unless it goes to water the well may produce for twenty or fifty or even seventy years, but each year it will produce less than the year before.
>
> Fields and individual wells vary greatly, but in general this year's production from a settled well produced to capacity will be from ten to thirty per cent less than last year's.[4]

Decline continues to be an integral part of oil and natural gas production, but its nature has changed. The graphic below demonstrates that unconventional wells begin as high production operations, decline rather quickly, and ultimately become low production wells.

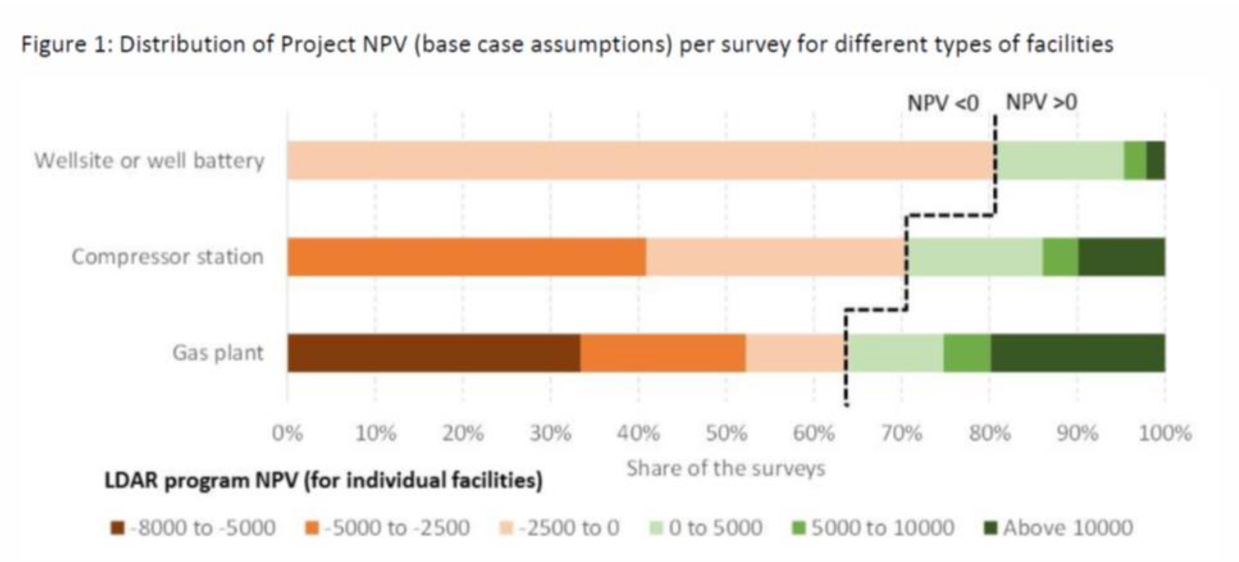


Consequentially, the EPA's determinations regarding the cost effectiveness of its fugitive emissions requirements on wells must be carefully examined. What may be a cost-effective

[4] Ball, Max W., This Fascinating Oil Business, The Bobbs-Merrill Company, 1940, p. 142.

program for high production operations will be very different as wells decline and become low production wells.

Unfortunately, this is not a new issue, but it is an issue that the EPA has largely ignored in the Subpart OOOOa regulatory process. In March 2014, Carbon Limits released a report: Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras.[5] This report produced a particularly telling assessment of the type program included in the Subpart OOOOa regulations and in the revised proposal. Notably, the report showed that the effectiveness of these LDAR programs for wells and well sites is highly limited. The following graphic is illustrative.



As the graphic demonstrates, for 80 percent of well sites, the LDAR program would create more than just an ineffective cost burden; it would create a negative net present value ("NPV"). Moreover, these results 'are based on natural gas prices of $4/mcf natural gas – well above the historic prices in the U.S. marketplace.

Most of these negative NPV wells are low production wells – wells that produce less than 15 B/D which is equivalent to gas production wells of 90 mcfd. Other experience with LDAR programs on low production wells demonstrates that the cost is excessive.

A California example is illustrative. This data comes from approximately 2,900 wells with an average production of 3.6 B/D; it includes 580,324 inspections which found 667 leaks. Using Leaker Emission Factors from 40 C.F.R. Part 98, Subpart W ("Subpart W") and assuming the leaks existed the entire quarter, the results are as follows:

Emissions Found

[5] See Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras, Carbon Limits (May 13, 2014), available at https://www.epa.gov/sites/production/files/2016-04/documents/quantifying_cost-effectiveness_leak.pdf

- 142 leaking valves at 13.9 thousand cubic feet ("mcf") per quarter ("qtr") leaker factor = 1974 mcf.

- 525 leaking connections at 12.3 mcf/qtr leaker factor = 6,457 mcf.

    - Total emissions = 8431 mcf

Cost of Recovered Gas

- The annual operating cost of LDAR equipment and crews only = $800,000. This is a low cost compared to existing Subpart OOOOa semi-annual requirements which has an estimated cost of $1,599/well or in this case $4,600,000/year.

- Using a very conservative estimate of $800,000/8413 mcf = $95/mcf.

- At $1,599/well the cost would be $4.6 million = $546/mcf.

Clearly, the cost of recovered emissions is far different than the value in the EPA's expectations. Importantly, these numbers are too low because the Emission Factor is a generic number – not one based on low producing wells. We will address this issue in more detail below.

However, the key point here is that low production wells need a program designed for their operations.

b. The EPA needs to provide an alternative approach for low production wells rather than a one time, ineffective assessment of a low production well.

In the Reconsideration Rulemaking, the EPA defines a low production well as:

> well sites with average combined oil and natural gas production for the wells at the site less than 15 boe per day averaged over the first 30 days of production ("low production well sites")[6]

As stated previously, oil and natural gas wells ultimately become low production wells. And, as low production wells, they have contributed or will continue to contribute to the nation's energy supply for decades. Currently, low production oil wells account for about 10 percent of American oil production, and low production natural gas wells account for 11 percent of American natural gas production. As a result of the additional cost associated with the fugitive emission surveying requirements in the Reconsideration Rulemaking, low production wells will be prematurely shut in and plugged. The nation will lose this reliable production.

The Reconsideration Rulemaking creates two pools of fugitive emissions requirements – one annual program for large production wells and one biennial program for low production wells. Setting aside for a moment the issues of the cost effectiveness of these programs, the approach creates some absurd results. In the approach taken by the EPA in the Reconsideration

[6] 83 Fed. Reg. 52,062.

Rulemaking, a well with production of 15 B/D after 30 days of production would be subjected to the biennial fugitive emissions program. However, a well with 18 B/D of production after 30 days would be perpetually in the annual fugitive emissions program even though it will clearly be below the 15 B/D threshold soon after its production starts.

Instead of this unworkable and unfair system, the EPA needs to craft an approach that allows wells when they begin producing less than 15 barrels of oil equivalent ("BOE") to shift to an alternative fugitive emissions program – a program based on the emissions pattern of low production wells. Such an approach would encourage the continued operation of wells as they decline but collectively provide an important component of the American oil and natural gas resource base.

Such an approach would not pose any adverse impact on the environment. First, the pool of wells producing American oil and natural gas is constantly changing. As it changes, older wells are being replaced with: 1) wells that meet the requirements of Subpart OOOO; and 2) many wells that used those technologies before Subpart OOOO as a part of the Natural Gas STAR program. Second, assuming the alternative as described above is created, a substantial portion of new wells are drilled on sites with multiple wells. Those well sites would continue to be subjected to the Subpart OOOOa fugitive emissions requirements until all of the wells became low production wells. Third, as discussed *infra*, the DOE is initiating a research program to define the emissions profile of low production wells. The EPA should use the results of that research to design an appropriate low production fugitive emissions program rather than try to shoehorn these wells into a program that was never designed for these operations.

Until then, the EPA should choose to act as it has in the October 2016 Control Techniques Guidelines ("CTG") for VOC emissions from existing oil and natural gas production facilities in ozone nonattainment regions and defer action on a low production well fugitive emissions program.

c. A Low production well is a low production well – regardless of when the well is drilled.

Characterizing wells in perpetuity based on the wells' first 30 days of production is arbitrary and unnecessary. The term "low production well" is a construct of these NSPS rulemakings but the concept or characterization of this category of wells is not new to the industry. The most recent characterization of "low production well" largely tracks commonly used approaches to defining smaller wells whether using the term low production well or marginal well or stripper well. These terms spring from the stripper well definition in the tax code. The use of the tax code definition should serve well as a definition for a "low production well" in any revisions to Subpart OOOOa that provide for regulatory actions regarding these wells. A principal issue in developing the low production well concept will be its application to each well. Inevitably, there will be challenges. Use of the tax code stripper well definition provides a long history of such determinations. It also provides a framework that is well understood by the regulated industry.

For example, one of the key issues in understanding the definition a low production well will be addressing production of both oil and natural gas which are common elements of these wells. That is, most oil wells will have associated gas and most natural gas wells will have natural gas liquids. These issues have arisen in the determination of stripper wells, and the process to determine their status has been refined over the years.

The essence of the stripper well provisions is found in Section 613A of the Tax Code. A stripper well is defined in Subsection (c)(6)(E):

> For purposes of this paragraph, the term "stripper well property" means, with respect to any calendar year, any property with respect to which the amount determined by dividing—
>
> > (i) the average daily production of domestic crude oil and domestic natural gas from producing wells on such property for such calendar year, by
> >
> > (ii) the number of such wells,
>
> is 15 barrel equivalents or less.

The calculation process to make this determination is straightforward. All production is converted to oil equivalents. To convert gas production to oil equivalents, a ratio of 6,000 cubic feet equals one barrel of oil[7]. Consequently, 90,000 cubic feet equals 15 barrels; this is the source in the low production definition that uses 15 B/D or 90 mcfd as its basis. However, the reality of the calculation revolves around putting all production on a common basis – oil. Thus, if a well produces 10 barrels of crude oil and 12,000 cubic feet of natural gas, its equivalent barrels produced would equal 12 (*i.e.*, 10 + (12,000 / 6,000)). This approach then resolves questions regarding how to evaluate wells with both oil and gas production.

Clearly, another issue that arises will be the application of the stripper well definition in the context of compliance assurance with Subpart OOOOa. Compliance assurance is always a significant question. But, using a known and understood criteria provides industry with a clearer standard. Most of the instances where the issue would arise is when a well declines, and this is the normal circumstance under which a well is assessed as a stripper well. The other instance that arises relates to the initial application of the regulatory requirements – in this instance the fugitive emissions monitoring program. The issue here involves the current requirements in Subpart OOOOa that the initial fugitive emissions monitoring occurs within 60 days of the startup of production, the determination of the well's status 30 days after its initial operation, and the tax code stripper well calculation that uses annual information. However, this issue could be resolved by creating some type of initial production threshold – *e.g.*, 250 B/D – that would suggest the likelihood that the well would decline to a low production well soon after its initial

[7] Section 613A (c)(4) Daily depletable natural gas quantity.

> For purposes of paragraph (1), the depletable natural gas quantity of any taxpayer for any taxable year shall be equal to 6,000 cubic feet multiplied by the number of barrels of the taxpayer's depletable oil quantity to which the taxpayer elects to have this paragraph apply. The taxpayer's depletable oil quantity for any taxable year shall be reduced by the number of barrels with respect to which an election under this paragraph applies. Such election shall be made at such time and in such manner as the Secretary shall by regulations prescribe.

operation. Wells meeting this threshold would have the initial fugitive emissions monitoring program delayed for one year. If the well did not fall below the low production well threshold by that time, the initial fugitive emissions monitoring could be required 60 days later.

Once revised Subpart OOOOa regulations address the pressing issue of providing an exclusion for low production wells and an offramp from the application of the Subpart OOOOa requirements when wells inevitably decline below the low production well threshold, the issue of interpreting the definition will clearly arise. Using the stripper well definition from the tax code brings with it a clear and certain process for determining its application. While the previously used EPA definitions of low production wells parallel the intent of the stripper well tax code definition, a new definition will lead to interpretation challenges that could be avoided.

C. <u>The EPA's Information on Low Production Wells is Inadequate to Develop Regulations</u>.

1. There are approximately 770,000 low production wells in the United States; the EPA is basing its model plant and emissions assessment on about 25 low production wells in one basin.

Perhaps the most significant aspect of Subpart OOOOa versus Subpart OOOO is that it is based on the regulation of methane instead of VOCs. A methane-based regulation not only addresses new and modified sources under Section 111(b), it opens the pathway to a nationwide existing source regulatory scheme under Section 111(d) of the CCA. Consequently, the scope of possible sources expands from the roughly 20,000 wells drilled annually to the 770,000 existing operating oil and natural gas wells. This is a vastly different regulatory expanse.

The EPA's approach to developing its low production well model plant ("Model Low Production Well") in the Technical Support Document ("TSD") and thereby its assessment of the effectiveness of a fugitive emissions program — returns to a fundamental question of the EPA's responsibility and obligation to develop its own data needed for regulatory actions. The data relied upon in the Reconsideration Rulemaking is wholly inadequate.

There are approximately 771,000 low production (marginal) wells in the United States — 394,000 oil wells, 377,000 natural gas wells. These wells are spread across over 30 states. The EPA's reliance on approximately 25 potentially low production wells in one play— the Barnett Shale in Texas — to define its Model Low Production Well is inadequate. This action is flawed for several reasons. First, there is no reason to believe that the Barnett Shale is representative of all low production wells in various plays across the country. Second, the data that was collected in the Fort Worth Study was not intended to address low production wells specifically and is simply a subset of wells incidental to a larger study. Third, even this well selection appears flawed; some wells do not appear to be low production wells. Fourth, and perhaps most importantly, trying to establish a Model Low Production Well on the basis of 25 single basin wells will lead to ineffective results and unproductive, inefficient use of resources

The same issue arises in the emissions analyses by various "Keep It in the Ground" environmental groups. The most prominent of these efforts relies on results from one or two basins, and the low production well data is an unintended subset of the larger study. That is, when the studies are made, there is no understanding of the production from the well. Afterwards, the analyses sort the data based on production, and some subset is low production wells. Even the larger compilations of these studies will include an accidental collection of less than 200 low production wells from one or two basins which is not the appropriate basis for developing national regulatory requirements impacting hundreds of thousands of wells.

2. The EPA's source documents on low production wells are critically flawed.

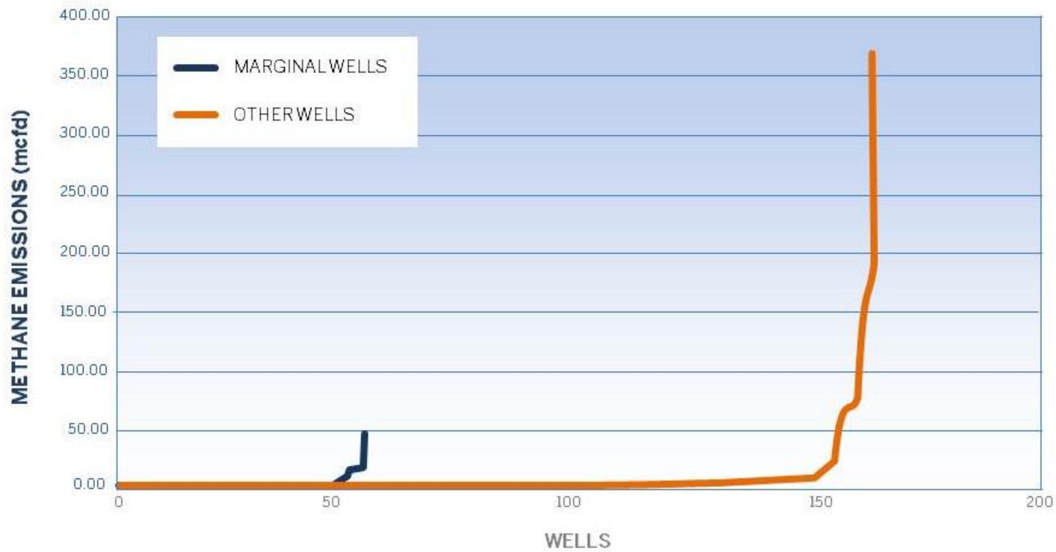
The flaws in the analyses by the EPA and Keep It in the Ground environmental groups that want to influence the EPA's decisions can be seen in a number of actions.

a. The Environmental Defend Fund's Super-Emitters Study is specious.

The Environmental Defense Fund's data manipulation in the study it submitted to the 2015 Subpart OOOOa rulemaking proposal distorts the role of low producing wells regarding methane emissions ("2015 EDF Study"). This study was then characterized as the basis for removing the low producing well exclusion for the Subpart OOOOa fugitive emissions program initially proposed by the EPA.

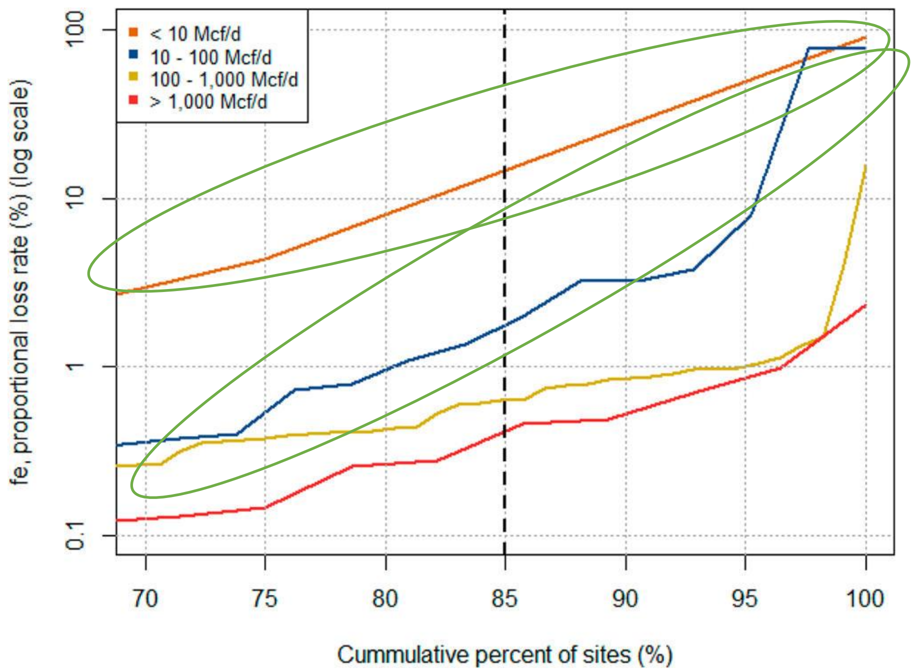
It is important to understand that the 2015 EDF Study used data from a number of different studies to create its arguments. All of the underlying studies generated their data by driving vehicles with samplers downwind of production sites, hunting for methane plumes. None of them used samples taken on the production site. This creates two issues. First, it measures everything emitted at the site – fugitive emissions and permitted vents. Second, the data are collected over minutes – maybe over an hour – but not over a day. The data in the study are presented as if they were daily emissions, but the studies merely scale up hourly estimates. Consequently, emissions that might occur for several hours, but not the full day, would be overstated.

Before turning further to describe the submitted study, it is useful to look at the same data using a direct graph of emissions. In this graph, marginal wells are those with production volumes of 90 mcfd or less – the EPA definition of low production wells.



This graph is consistent with information from other studies showing that a small portion of wells have an emission profile for some reason with high emissions while most wells have really low emissions. Importantly, it also clearly shows that low production wells have far smaller emissions. But, since this graph is using the same data as the study, it could also be overstating emissions because of scaling short-term emissions to a daily amount.

With this background, turning to the presentation of the same material in the study demonstrates how it was manipulated. Below is the graphic used to present the data. It would suggest that the worst emitting operations – the "super-emitters" – are the smallest wells (the orange line and the blue line, circled in green). Having directly plotted this data, the obvious issue is how such a result can occur.



It is a busy and confusing graph – it is intended to be. The study uses data analysis tricks to create the appearance that low production wells are "super-emitters."

First, it shows emissions as a percentage of production rather than actual emissions. Thus, one mcf emitted out of ten mcf produced is 10 percent, but 50 mcf emitted out of 1,000 mcf produced is five percent. As a result, it skews the perception of the data to imply that low production wells are large emitters when they are not.

Second, its production volumes are really sales volumes, not the amount extracted from the wellhead. Consequently, a "proportional loss rate" of 50 percent would be the calculated loss divided by the volume sold. If the percentage of loss was calculated based on extracted volumes, the 50 percent "proportional loss rate" would drop to 33 percent because the loss would be added to the sales volume to obtain the extracted volume.

Third, it only shows data from the 70th percentile of information. This excludes all of the virtually zero emissions that dominate the data.

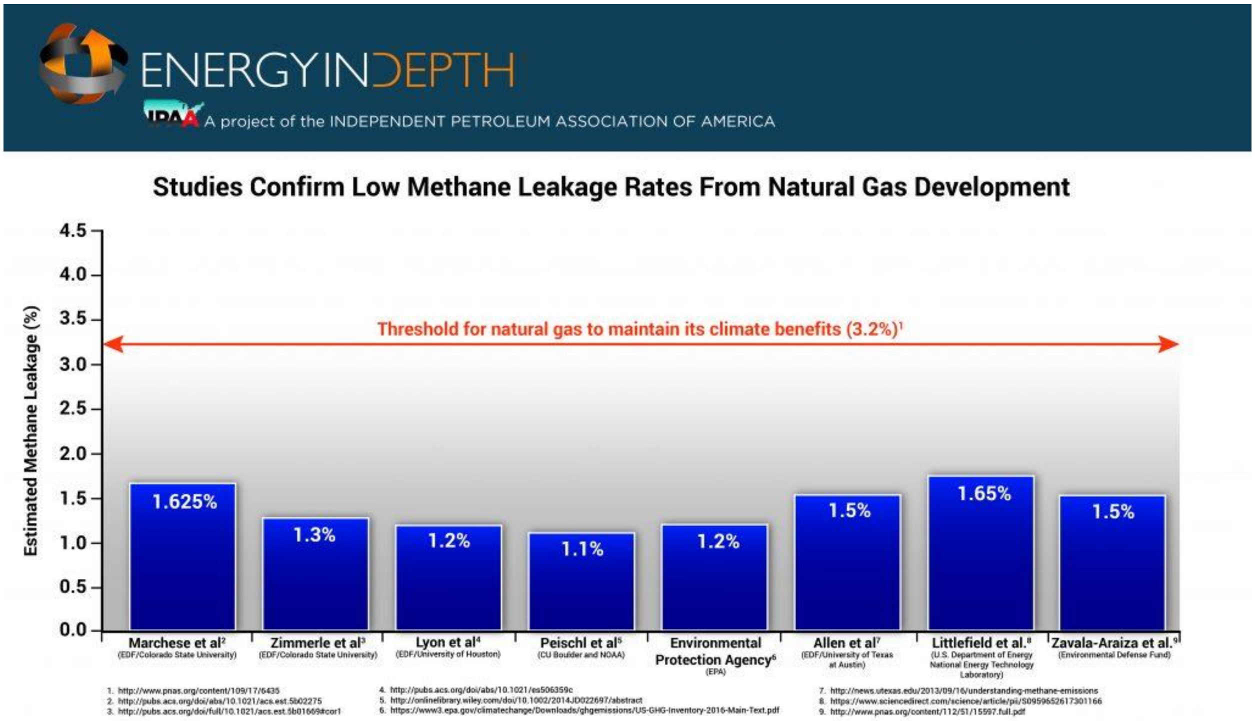
Fourth, it uses a logarithmic scale to present the data. One of the reasons to use logarithmic scales is to flatten curves to make them look more like straight lines.

The EPA should not have relied on such a specious report to make a regulatory decision with profound effects on the future of American oil and natural gas production.

b. The EDF 5-Study report is equally flawed.

In May 2018, EDF released another methane emissions study ("2018 EDF Study") that it heralded as another example describing the underestimation of national methane emissions and demanding more federal regulation. It is as specious as the 2015 EDF Study and should be given no import by the EPA in assessing regulatory options. Following is a discussion of its key failings.

To put this discussion in context, the EID addressed the 2018 EDF Study.[8] Its analysis follows:



*The Environmental Defense Fund (EDF) has **released a myriad of studies** on natural gas system methane emissions over the past six years that have found low leakage rates between 1.2 and 1.5 percent of production. Five such studies are featured in the following EID graphic.*

*So the fact that a new EDF **study** released today finds methane leakage rates of 2.3 percent — well above what EDF-led research has previously found and "60 percent higher than the U.S. EPA inventory estimate," according to the report — begs the question: What changed with regard to EDF's methodology for this study that yielded a much higher leakage estimate than its past research has shown?*

---

[8] Whitehead, Seth, Five Things to Know About New EDF Methane Study, Energy in Depth (June 21, 2018), https://www.energyindepth.org/five-things-to-know-about-new-edf-methane-study/

Turns out, quite a lot changed, and most of the changes raise red flags regarding the study's conclusions. Not only did the authors of the new EDF study — which includes no new measurements and instead calculates national methane emissions based on past studies — opt not to use past EDF research as a basis for their emissions calculations, it relies exclusively on five far less comprehensive facility-level studies that lacked industry participation to arrive at its conclusion of higher U.S. emissions than previously reported. In contrast, an "alternative" calculation, based partially on EDF's past studies, that finds emissions in line with current EPA estimates is buried in the study's supplemental data and is not even mentioned in the report.

These are just two of several key issues regarding the manner in which EDF conducted this study that appear aimed at producing the most extreme emissions estimate possible ahead of the 27th annual ***World Gas Conference*** *(WGC), which begins Monday in Washington, DC. Here is a deeper look at each issue.*

#1. Exclusive Use of Facility-Scale Study Data Goes Against National Academy of Sciences' Recommendations and Likely Exaggerates Emissions

This study's national methane emissions estimate is based entirely on downwind, facility-based studies. From the report:

"In this work we integrate the results of recent facility-scale BU studies to estimate CH4 emissions from the U.S. O/NG supply chain, and then we validate the results using the TD [top-down] studies."

However, a recent National Academy of Sciences (NAS) ***report*** *aimed at improving national methane emissions inventories recommends a more comprehensive approach combining "bottom-up" measurements — both of the component- and facility-level variety — along with "top-down" measurements:*

"Coordinated, contemporaneous top-down and bottom-up measurement campaigns, conducted in a variety of source regions for anthropogenic methane emissions, ***are crucial for identifying knowledge gaps and prioritizing emission inventory improvements****. Careful evaluation of such data for use in national methane inventories is necessary to ensure representativeness of annual average assessments."*

EDF has conducted studies combining the comprehensive top-down/bottom-up methods recommended by NAS before. ***Zavala-Araiza et al.*** *is the most notable example, and that study found a methane leakage rate of just 1.5 percent. Just as notably, a recent National Energy Technology Laboratory* ***study*** *based on Zavala-Araiza et al. data estimates national methane emissions at 1.65 percent. That report involved several of the co-authors of this most recent EDF study that reached much different conclusions.*

The new EDF report argues that using facility-level measurements exclusively is appropriate because component-based studies can "under-sample abnormal operating conditions" such as malfunctions and large leaks. But this rationale ignores flaws with facility-level measurements that can lead to overestimation of emissions. For instance, facility-level measurements can capture episodic emissions, such as liquids unloading, *and inaccurately characterize them as normal emissions that would be occurring 24 hours a day, seven days a week. The latter issue can be exacerbated when researchers lack a fundamental understanding of the facilities where they are taking measurements, which brings us to the next major issue with the study.*

#2. Lack of Industry Collaboration Goes Against National Academy of Sciences' Recommendations

With regard to the ground-based, facility-level studies used as the basis for estimating national emissions in this report, the report's supplementary information document notes:

*"Sites were reported to be sampled on a quasi-random basis **without advance operator knowledge**."*

*Not only does EDF admit that some of the studies used did not conduct truly random sampling, it admits that industry wasn't involved in these studies on any level. This again flies in the face of recommendations made in the **NAS** report, which states:*

"[V]erifiability is the bedrock upon which inventories should be built if they are to be widely applicable to policy needs."

*The lack of industry participation is surprising, considering EDF's past methane research is well known to have been a collaborative effort between EDF, academia and industry, a fact EDF has frequently **touted**. But even more surprising is EDF's justification for excluding industry from participating in this particular study. From the report:*

*"Operator cooperation is required to obtain site access for emission measurements. Operators with lower-emitting sites are plausibly more likely to cooperate in such studies, and workers are likely to be more careful to avoid errors or fix problems when measurement teams are on site or about to arrive. The **potential bias** due to this 'opt-in' study design is very challenging to determine. We therefore rely primarily on site-level, downwind measurement methods with **limited or no operator forewarning** to construct our BU estimate."*

Not only does EDF fail to provide a single reference to back up this claim of "potential bias" that it claims necessitated it to use the methodology highlighted above, but none of the five co-authors of this report, who were also the lead authors of past EDF methane research that was conducted in close concert with industry,have ever publicly claimed any "bias" whatsoever. Not once.

EDF's assertion appears to be purely speculative in nature and also appears to be an excuse to use these studies as a basis for exaggerated national emission estimates.

#3. "Alternative" Emissions Estimate That Is In Line With EPA Greenhouse Gas Inventory (And Past EDF Research) Is Not Included In Report

In the supplemental materials document for this report, EDF includes the following "alternative" national emissions estimates based on source-based reports, several of which are past EDF studies.

Source: Table S3	GHGI	Source-based EDF estimate (Gg CH4/yr) – Alternative EDF estimate	Site-based estimate (Gg CH4/yr) – Primary Method
Total U.S. Oil and Gas Supply Chain	8,100 (6,800 – 10,000)	8,800 (8,400 - 9,700)	13,000 (12,000 - 15,000)

Source: Alvarez et al. supplementary materials

*This "alternative" estimate finds the national methane leakage rate is 1.4 percent, which (not surprisingly) not only aligns with past EDF studies, but also the **EPA Greenhouse Gas Inventory**.*

Remarkably, the data from this "alternative" estimate isn't mentioned at all in the actual report, even though EDF notes that an extensive list of source-based studies featured in the supplemental data of the report has "dramatically improved understanding of the sources and magnitude of CH4 emissions from the industry's operations."

EDF also argues that its "primary" estimate — which, again, is based solely on facility-level studies — is in line with aggregate average emissions found in the following nine "top-down" studies based on emission measurements largely collected via aircraft measurements.

"When the BU estimate is developed in this manner, direct comparison of BU and TD estimates of CH4 emissions in the nine basins for which TD measurements have been reported indicates agreement between methods…"

Table S2. Reported estimates of O/NG CH_4 emissions from aircraft-based top-down (TD) studies, listed in decreasing order of natural gas production. Italicized values were calculated in this work; shaded rows indicate a second independent, statistically consistent set of reported measurements in two basins (not used directly in this work in favor of the more recent results based on more intensive sampling). Uncertainties are 2-sigma values calculated from reported uncertainties.

TD survey area	Reference	Date Sampled (Month/yr)	Days/flights/ downwind transects	NG production (bcf/d)	% CH_4 in NG	Upwind Background Method*	Total CH_4 Flux (Mg/h)	O/G apportionment method†	O/NG CH_4 flux (Mg/h)†	Production normalized emission rate$
Haynesville	Peischl (*51*)	6/2013	1/1/3	7.7	86%	UTA	80 ± 54	SE	*73 ± 54*	*1.3%*
Barnett	Karion (*71*)	3 & 10/2013	8/8/17	5.9	89%	DL	76 ± 13	E	60 ± 11	*1.4%*
NE PA	Barkley (*67*)	5/2015	4/4/7	5.8	95%	MUT	20 ± 17	SE	18 ± 14	*0.40%*
NE PA	Peischl (*51*)	7/2013	1/2	N/A	95%	UTA	15 ± 12	SE	13 ± 12	*0.30%*
San Juan	Smith (*52*)	4/2015	5/5/5	2.8	83%	DL	62 ± 46	N	*57 ± 54*	*3.0%*
Fayetteville	Schwietzke (*47*)	10/2015	2/2/4	2.5	97%	UTSV	31 ± 8	SE	27 ± 8	*1.4%*
Fayetteville	Peischl (*51*)	7/2013	1/1/2	N/A	97%	UT	39 ± 36	SE	35 ± 32	*1.9%*
Bakken	Peischl (*49*)	5/2014	3/3/5	1.9	47%	DL	28 ± 10	SE	27 ± 13	*3.7%*
Uinta	Karion (*69*)	2/2012	1/1/1	1.2	89%	UT	56 ± 30	S	55 ± 31	*6.6%*
Weld	Petron (*70*)	5/2012	2/2/3	1.0	79%	UT	26 ± 14	S	19 ± 14	*3.1%*
W Arkoma	Peischl (*51*)	7/2013	1/1/1	0.37	96%	UT	33 ± 30	S	26 ± 30	*9.1%*
9-basin total				29			410 ± 87		360 ± 92	1.8 ± 0.5%¶

* Upwind background methods: UT=upwind transect; UTSV = spatially variable upwind transect; UTA=upwind transect with adjustments to account for methane above background that flows into a region; DL = downwind lateral plume edges; MUT = model-assisted upwind transect

† Apportionment methods: S= subtraction of inventory-based estimates of non-O/NG sources; E = ethane; SE = subtraction with ethane as qualitative check; N = none

$ Methane emitted normalized by methane produced

¶ Production weighted

Source: Alvarez et al. supplementary materials

But this claim is a stretch on a couple levels. First, the cumulative data from the above "top-down" studies show a national leakage rate of 1.8 percent, well below the 2.3 percent leakage rate this new EDF study claims. Though that is within the study's .5 percent uncertainty range, top-down studies typically overestimate oil and gas methane emissions due to the fact that emissions measurements from such studies are difficult to attribute to specific sources.

In other words, it is highly implausible that "bottom-up" methane emissions estimates would be higher than "top-down" estimates.

And in fact, a recent National Oceanic Administration (NOAA) ***study*** *finds that top-down studies have likely overestimated emissions by mischaracterizing episodic emissions as normal emissions. Such emissions can also be detected and mischaracterized via facility-level measurements. So it's not surprising that this EDF study tries to discredit that NOAA study.*

#4. Attempts to Discredit Study That Finds Misrepresentation of Episodic Events Can Lead to Inflated Emissions Estimates Via Daytime Bias

Another factor that can lead to facility-scale measurements overestimating actual normal emissions is the fact that such methods are conducted in the daytime and, thus, can capture emissions from episodic events – such as liquids unloading – that are conducted during the day and inaccurately extrapolate them as if they are constant. This fact was further confirmed by a recent peer-reviewed NOAA study of the Fayetteville Shale ***covered*** *by EID last year.*

Perhaps anticipating that 2017 study would be used to call this new EDF report's conclusions into question, EDF attempts to discredit the NOAA study in the paper:

"[W]e consider unlikely an alternative hypothesis that systemically higher emissions during day-time sampling cause a high bias in TD methods."

"[T]here is no reason to expect daytime bias in the kinds of abnormal operating conditions that are thought to characterize high-emitting production (and gathering) sites, which operate continuously. In fact, it is plausible that abnormal emissions could actually be higher at night because they are less likely to be found and corrected in the absence of operators."

The above claim is directly contradicted by the following, which acknowledges the validity of the NOAA Fayetteville study, but claims it isn't relevant to other basins.

"O/NG emissions are systematically higher during daytime hours when TD and BU measurements have been made, and lower at night. This situation was reported for the Fayetteville Shale but appears to be unique because the effect is caused by manual liquids unloadings, which represent a much higher fraction of total production emissions than in any other basin."

The fact is, events such as liquid unloadings are common in other basins and downwind measurements, such as the ones used as the basis for this EDF analysis, do tend to be higher because they are conducted during the day.

#5. Despite EDF's Alarmist Characterizations, Natural Gas' Climate Benefits Remain Clear

The report claims the oil and natural gas development emissions level estimated in this report combined with carbon emissions from current natural gas combustion is having the same climate impact as coal in the short term (20-year timespan):

"Indeed, our estimate of CH4 emissions across the supply chain, per unit of gas consumed, results in roughly the same radiative forcing as does the CO2 from combustion of natural gas over a 20-year time horizon (31% over 100 years). Moreover, ***the climate impact of 13 Tg CH4/y over a 20-year time horizon roughly equals that from the annual CO2 emissions from all U.S. coal-fired power plants operating in 2016*** *(31% of the impact over a 100-year time horizon)."*

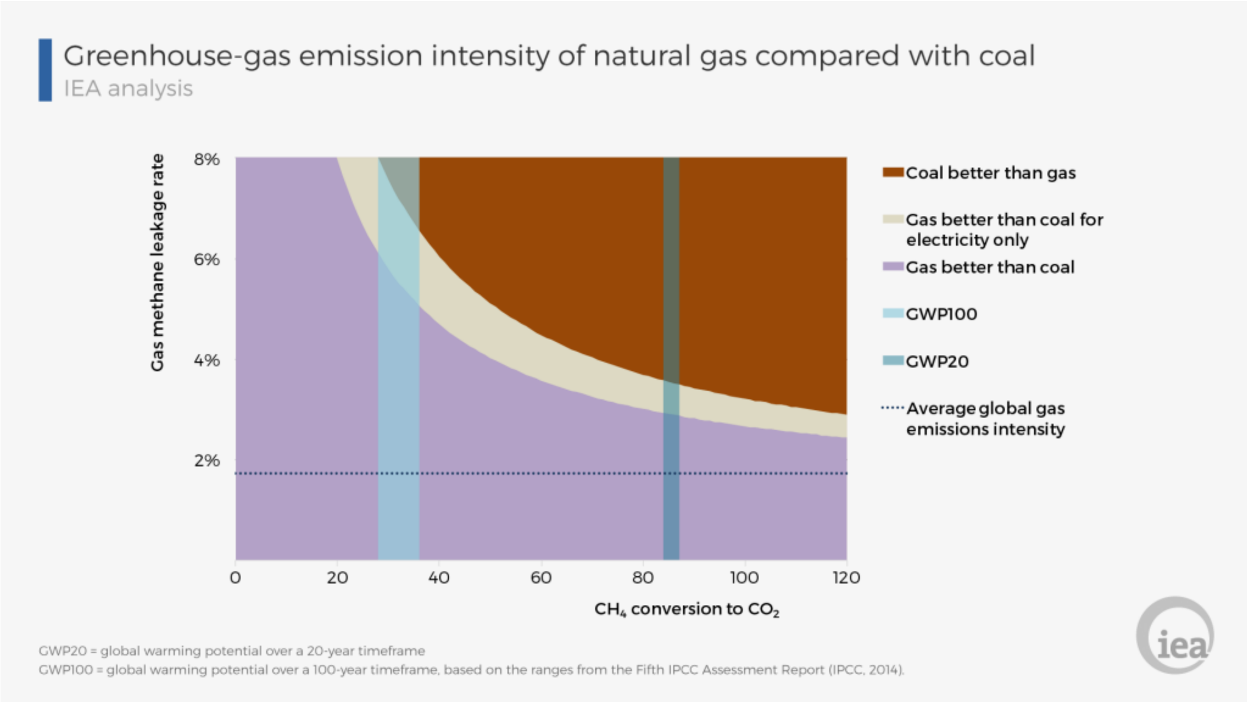
But as alarming as that claim might be, it is essential to note that natural gas maintains clear climate benefits over other traditional sources even at much higher leakage rates than purported by this study.

A recent hydraulic fracturing issues brief published by Washington D.C.-based environmental think tank Resources for the Future (RFF) ***notes****:*

"If more than about 4% of the natural gas produced in the United States is emitted as methane (rather than being burned), the climate benefits of gas's displacement of coal

disappears over a 20-year time frame. If the time frame is 100 years, the leakage rate would have to be more than 8% for natural gas to be a climate loser relative to coal."

The following International Energy Agency (IEA) graphic illustrates RFF's point, showing natural gas maintains its climate benefits even at high leakage rates and regardless of time-frame considered.



Conclusion

This EDF study spends an inordinate amount of time explaining why its conclusions are plausible rather than explaining how it reached its conclusions. And it's clear why — once one digs into the report's supplemental information, it's clear that the conclusions are based on some pretty shaky assumptions and speculation that runs counter to established and/or recommended best practices for such research.

*But at the end of the day, the EDF study is not only an outlier in terms of the overall body of current methane research — it's also an outlier with regard to EDF's collective methane research, which has consistently found leakage rates between 1.2 and 1.5 percent. In the meantime, EPA **data** show oil and gas methane emissions have declined 14 percent since 1990 even as oil and natural gas production have skyrocketed. Combined with the fact that increased natural gas use has helped contribute to the best air quality of the modern era and the lowest carbon emissions in 25 years, it is clear that the shale revolution has been a win-win for the economy and environment.*

As EID described above, the EDF developed no new data; it used data from other studies. These included some of the same data from the EDF's earlier specious "Super Emitters" report. Unsurprisingly, plotting the data from this study follows the same pattern as other studies, including low production wells having a much lower final emissions point than larger wells. But, this reality does not prevent EDF from casting unwarranted allegations about low production wells.

Correspondingly, the EDF report builds its conclusions on the same flawed underlying information. Because the collected data on emissions comes from short-term, remote monitoring (drive by monitoring), it inherently means that (1) the emissions information cannot distinguish between permitted emissions like storage tank vents and equipment leaks, (2) it cannot distinguish daily emissions from short-term sporadic emissions due to maintenance activities, and (3) it is skewed toward overestimating emissions by converting these short-term measurements into daily emissions rates. The 2018 EDF Study is inaccurate and unreliable.

The EDF's biases are reflected in other aspects of its report. For example, in the report, the authors make the following observations related to "top down" data collections:

> Notably, the two largest sources of aggregate emissions in the EPA GHGI – pneumatic controllers and equipment leaks – were never observed from these aerial surveys.

A true analyst might have assessed this information and asked some probing questions. For example, if these sources were not shown as substantial emissions, could that mean that the EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks ("GHGI") emissions factors were overstating the emissions? Other studies have suggested that the EPA emissions factors for certain types of pneumatic controllers that are widely used at production sites are overestimating emissions by a factor of 100[9,10]. Various studies evaluating fugitive emissions programs have suggested that the expectations of reductions from these programs are significantly overstated[11]. Did these analysts consider the import of these data? Of course not. They noted it in passing and used the EPA GHGI emissions factors in calculating their "bottom up" site-based emissions estimates.

It is somewhat difficult to follow the convoluted path that the EDF takes to generate its excessively high emissions estimates. What is clear is that the EDF devises a series of assumptions to argue that emissions are related directly to natural gas production. At least for oil and natural gas production, this conclusion runs directly contrary to all other assessments that have shown methane emissions falling as production increases — results that are in part due to voluntary actions and in part to regulatory requirements such as Subpart OOOO.

---

[9] Whitehead, Sean, New EPA Study Indicates Agency Is Greatly Exaggerating Methane Emissions, Energy In Depth (May 8, 2017), https://www.energyindepth.org/new-epa-study-indicates-agency-greatly-exaggerating-methane-emissions/

[10] Oklahoma Independent Petroleum Association, Pneumatic Controller Emissions from a Sample of 172 Production Facilities (November 2014), https://www.oipa.com/page_images/1418911081.pdf

[11] Whitehead, Seth, New Study Challenges Claim That Methane Emissions From Oil and Gas Are Higher Than EPA Estimates, Energy In Depth Climate & Environment (October 29, 2018), https://eidclimate.org/study-challenges-methane-oil-gas-epa/

This approach yields some specific, highly questionable results, including a conclusion that 26 to 30 percent of methane emissions result from natural gas and oil wells with production rates at or below 10 mcfd. This includes calculated emissions estimates derived from the mathematical assumptions in the studies for wells where no data existed. For these small wells with emissions, the EDF bases its determinations on escalating short-term data – emissions during an hour or less – into daily rates from less than 30 natural gas wells.

This EDF Study, like its predecessors, suffers from the same underlying intent. Its purpose is to distort the perception of success in understanding methane emissions and the efforts to reduce them. Its purpose is to drive new regulations — particularly regulations of low production wells, new, modified and existing. The EPA should not accept or rely upon such flawed data for making regulatory decisions.

c. Fort Worth Study data is highly questionable.

The EPA relies heavily on data from a study in Fort Worth, Texas, on wells in the Barnett Shale formation. Unlike most studies, this one was conducted with the cooperation of natural gas producers and included facility information. While the emissions data was taken by offsite mobile sampling for short time periods like the other emissions data referenced in the EDF studies, detailed production site information was provided. The EPA relies on this information to develop its Model Low Production Well. However, like all other studies, the Fort Worth study collected data broadly, capturing both low production wells and large wells. Low production wells were not specifically targeted or defined at the time of the data collection.

The EPA has now apparently extracted from the larger data base those wells with production at or below its 90 mcfd low production well threshold. It includes 25 dry gas wells and two wet gas wells. However, a closer examination of this data demonstrates key flaws. These flaws are important because the selected wells then shape the model facility. The model facility then becomes the basis for the low production well emissions estimates that then justify the requirements for the fugitive emissions program.

For example, of the 25 dry gas wells, eleven wells show no production at the time that the emissions data was taken. The consequence of including the wells with zero or less than one mcfd is the impact on the number of pieces of equipment at a site that then becomes the basis of the model facility and the basis for emissions estimates from these wells. For example, the number of valves at a site drives valve emissions which are a significant factor in the total low production model facility emissions calculations. With all 25 sites in the calculation, the EPA generates an average valve number of 108. However, if the zero and less than one mcfd wells are removed, the average valve number drops to 75. Similarly, the number of tanks per well site drops from two to one.

Better information on the nature of low production well sites is needed to assess an appropriate model well facility if a model facility is even appropriate given the diversity of production across basins.

d. Use of 1995 emissions factors raises issues of accuracy.

The EPA's use of 1995 emissions factors to develop its Model Low Production Well emissions estimates must be tested for accuracy. The 1995 effort for oil and natural gas production facilities is primarily based on an American Petroleum Institute ("API") document – API 4615 – that was prepared for generally predicting emissions levels. This is a different purpose than creating emissions factors for the purpose of regulations.

Among the key issues that bear here is whether that 1995 analysis attempted to determine distinctions between large production facilities and low production facilities. In the instant case, that distinction is significantly important because the EPA is using these factors for exactly the purpose of regulating low production wells and determining the effectiveness of its proposed program.

To present the issue in the context of its uncertainty, the emissions factor for valves – the largest component of emissions in the EPA's natural gas Model Low Production Well – is 4.5E-03 or 0.0045 kg/hr/component. The API analyzed the effectiveness of LDAR programs and compared them to EPA's assumptions in designing its LDAR program. It found that the EPA's assumptions regarding initial failure rates and the time before further maintenance or repair of equipment was necessary were inaccurate. The API data demonstrated that the EPA's assumptions overstated initial failure rates and predicted the need for further maintenance too soon. Consequently, the combination of these assumption overstates the benefits of the EPA LDAR and its cost-effectiveness. Additionally, the API's letter to the EPA submitting its information on February 22, 2018, includes updated emissions factors for component leaks at oil and natural gas production facilities. In the case of valves, the new emissions factor is 1.1E-03 or 0.0011 kg/hr/component. This factor that is 25 percent of the factor used by EPA in its Model Low Production Well.

The point here is that there are key assumptions that are highly questionable and more accurate information is essential.

3. **<u>The EPA's Model Low Production Well needs improvement.</u>**

The EPA creates a Model Low Production Well to define and determine the emissions and the effectiveness of its proposed low production well fugitive emissions program. The Independent Producers continue to evaluate and have certain concerns with the approach that the EPA takes in developing low production well emissions. The EPA appears to be fixated on the use of component counts to define emissions. While it is reasonable to associate the number of connections and the potential for leaks, we continue to believe that emissions from low production wells are inherently different from large production wells because of the basic physics of production and how operators change the physical equipment as production warrants.

When oil and natural gas wells are initially produced, the geologic forces that are released through the well bore drive initially higher production rates. Like releasing air from an inflated balloon, high pressure from the formation pushes flow of oil and natural gas through the well. These higher pressures and strong volumes of fluids define the design parameters for the well and the surface support equipment when the well is first drilled.

However, as wells age and production declines, conditions change. Pump jacks, if not used from the onset of production, are required to pull oil from the formation; compressors may be needed to suck natural gas from wells, while other equipment is removed or downsized. Secondary and tertiary recovery methods are used to produce more oil and natural gas from conventional formations.

These changes have consequences on the nature of emissions, particularly fugitive emissions. Like the challenge of getting the last air out of a balloon, the movement of gas molecules will follow the path of least resistance. Movement from the process equipment to the atmosphere is harder than moving to the production vessel where the flow is designed to go.

For these reasons, the Independent Producers object to relying upon component counts as the primary if not sole basis for estimating low production well emissions. Nevertheless, if the EPA intends to use component counts, we must assure that its assumptions are accurate. Based on a review of the TSD associated with the Reconsideration Rulemaking and data collection from many individual companies from various plays across the country, the Independent Producers believe the EPA continues to overestimate emissions from low producing wells.

a. The model plant is dominated by two elements – valves and storage vessels.

Because the EPA relies on component counts for its emissions estimates, it is essential to look at the mix of components and the application of emissions factors to them. The EPA divides its model facility by different types of equipment – wellheads, separators, headers, heater treaters, glycol dehydrators and storage vessels. For each type of equipment, it counts the following components – the number of specific equipment types on site, valves, connectors, open ended lines ("OELs") and pressure relief valves ("PRVs"). In reviewing the TSD, the dominant components driving the model facility plane are the number of valves and the number of storages vessels per facility. Following are the tables from the TSD for the Model Low Production Well.

Table 2-2. Average Fugitive Emissions Component Count for Low Production Well Site Model Plants

Production Equipment	Model Plant Equipment Counts	Average Component Count Per Unit of Model Plant[a]				
		Valves	Connectors	OELs	PRVs	Thief Hatches
Low Production Natural Gas Well Site Model Plant						
Wellheads	2	19.0	74.0	2.0	0.0	--
Separators	2	43.0	137.0	8.0	3.0	--
Meters/Piping	1	13.0	48.0	1.0	0.5	--
In-Line Heaters	0	0.0	0.0	0.0	0.0	--
Dehydrators	1	24.0	90.0	2.0	2.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	100.0	349.0	12.0	5.0	1.0
Low Production Oil Well Site (<300 GOR) Model Plant						
Wellheads	2	8.0	6.0	0.0	2.0	--
Separators	1	5.0	8.0	0.0	0.0	--
Headers	1	4.0	3.0	0.0	0.0	--
Heater/Treaters	1	6.0	15.0	0.0	0.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	23.0	32.0	0.0	2.0	1.0
Low Production Oil with Associated Gas Well Site (>300 GOR) Model Plant						
Wellheads	2	8.0	6.0	0.0	1.0	--
Separators	1	5.0	8.0	0.0	0.0	--
Meters/Piping	2	20.0	72.0	1.0	1.0	--
Headers	1	4.0	3.0	0.0	0.0	--
Heater/Treaters	1	6.0	15.0	0.0	0.0	--
Storage Vessels	1	--	--	--	--	1.0
	Rounded Total	44.0	105.0	1.0	3.0	1.0

a. Data Source for average component count per equipment type: EPA/GRI, CH_4 Emissions from the Natural Gas Industry, Volume 8: Equipment Leaks, Table 4-4 and 4-7, June 1996. (EPA-600/R-96-080h). Values were multiplied by the rounded equipment count for model plant component counts.

In the most notable example above, the EPA's use of the 25 gas production facilities, with its high count for valves, drives an emission estimate that the EPA then uses to justify its formulation of a low production well fugitive emissions program. These estimates are shown below:

Model Plant Component Type	Model Plant Component Count	Uncontrolled Emissions Factor[a] (kg/hr/component)	Uncontrolled Emissions (tpy)	
			Methane[b]	VOC[c]
Low Production Gas Well Site				
Valves	100	4.5E-03	3.01	0.84
Flanges	0	3.9E-04	0.00	0.0
Connectors	349	2.0E-04	0.47	0.13
OEL	12	2.0E-03	0.16	0.05
PRV	5	8.8E-03	0.30	0.08
Thief Hatch	1	0.1296	0.87	0.24
		Total	4.80	1.34

Low Production Oil Well Site				
Valves	23	4.5E-03	0.69	0.19
Flanges	41	3.9E-04	0.11	0.03
Connectors	32	2.0E-04	0.04	0.01
OEL	0	2.0E-03	0.00	0.00
PRV	2	8.8E-03	0.12	0.03
Thief Hatch	1	0.1296	0.87	0.24
		Total	1.83	0.51

Low Production Oil Well Site w/Associated Gas				
Valves	44	4.5E-03	1.33	0.37
Control Valves	41	3.9E-04	0.11	0.03
Connectors	105	2.0E-04	0.14	0.04
OEL	1	2.0E-03	0.01	0.00
PRV	3	8.8E-03	0.18	0.05
Thief Hatch	1	0.1296	0.87	0.24
		Total	2.63	0.73

In each of these cases, the primary factors in the emissions profile are valves and thief hatches on storage vessels. If either of these factors is overstated, the impact on the cost effectiveness of the fugitive emissions regulations can be significant. As we presented above, the emissions factor for valves comes from general information on oil and natural gas production operations in the mid-1990s. Among the questions it raises are:

- Is the emission factor accurate for low production wells?
- Would the emission factor be the same for oil service and gas service?

- Do emissions vary with valve activity?

The second key component in the calculation involves an accurate assessment of the number of valves at a low production well facility. There are many factors that define the number of valves at a particular facility, obviously one being the amount of equipment at the site. Equipment changes over time as facilities respond to declining production. Different parts of the country need different equipment. For these reasons, the EPA's use of a limited number of wells – 25 to 27 wells in the Barnett Shale for natural gas production raises clear questions about whether this limited selection of wells is reflective of low production wells nationally. It creates an even more significant question in the context of a possible nationwide existing source regulatory initiative under Section 111(d) which would bring in 770,000 wells with life spans covering decades of production.

For this reason, we solicited information from oil and natural gas producers from across the nation regarding the structure of their low production facilities. This effort presents in clearer focus that attempting to use a model well facility to justify regulations falls short of the regulatory burden that EPA should bear in understanding the consequences of its actions.

b. Industry information from across the country shows different equipment counts that dispute the model well which is primarily based on the Fort Worth Study.

In response to these Comments, the Independent Producers solicited available information on component counts from low production wells across the nation. These results are not intended to be presented as statistically accurate or fully representative of the population of low production wells. However, they are illustrative of the challenge of defining a Model Low Production Well plant. We obtained information from operations in thirteen states – Arkansas, Colorado, Indiana, Kansas, Kentucky, Michigan, Montana, Nebraska, Ohio, Oklahoma, Pennsylvania, Texas, and Virginia. Information was provided on over 2,400 wells, almost 1,700 of which are natural gas wells. We defined natural gas wells as well with a gas/oil ratio of 5.0 based on BOE. Because the most questionable aspect of the EPA model well calculations relates to the assumptions related to the number of valves in natural gas operations, we will present that information here.

i. Number of valves is well below model plant; wellhead assumption is too high.

Following are tables from the states with reported information from natural gas sites. A first point in this information that bears on the calculations is that this natural gas low production well information shows that typical plant has one wellhead rather than the two wellheads in the EPA model plant. Inherently, this likely reduces the number of valves, but it should not be interpreted to mean that doubling the number of valves would be appropriate in the creation of a model plant with two wellheads. Moreover, it also emphasizes the burden of the Optical Gas Imaging ("OGI")-based fugitive emissions program on these smaller operations. These tables provide information on the average number of storage vessels, wellheads and valves at these natural gas production plants.

PENNSYLVANIA

The following table presents information based on 1631 natural gas well sites.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
PA	1	1	23

OKLAHOMA

The following table presents information based on 27 natural gas well sites. However, two of these sites have larger numbers of valves; 236 and 177. If those sites were removed from the total, the average number of valves would drop to 24 per wellsite.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
OK	2	1	38

OHIO

The following table presents information on 10 natural gas well sites.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
OH	10	10	22

TEXAS

The following table presents information on 10 natural gas well sites.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
TX	2	1	25

KANSAS

The following table presents information on six natural gas well sites.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
KS	1	1	11

MICHIGAN

The following table presents information on four natural gas well sites. However, one of these sites has 161 valves and 5 storage vessels. If this site was removed, the average number of valves would decrease to 17.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
MI	3	2	53

KENTUCKY

The following table presents information on two natural gas well sites.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
KY	1	1	14

VIRGINIA

The following table presents information on one natural gas wellsite.

State	Number of Storage Vessels	Number of Wellheads	Number of Valves
VA	1	1	12

c. EPA model plant calculations attribute 80 percent of low production natural gas wells to valves (63 percent) and thief hatches (18 percent) and 85 percent of low production oil wells to valves (38 percent) and thief hatches (48 percent). These calculations are based on questionable emissions factors.

Deconstructing the EPA's Model Low Production Well reveals that the primary factors in defining emissions are valves and thief hatches. This holds true for both natural gas and oil wells although valves are far more of a factor in the Model Low Production Well. The Independent Producers believe this calculation is highly questionable. As the Independent Producers have set forth above, both of the underlying assumptions on valves – the emissions factor and the number of valves – are not appropriately validated for the purpose of creating a costly regulatory program.

The valve emissions factor hinges on assumptions of the initial levels of emissions prior to the LDAR program and the recurrence of those emissions levels. Yet, the API analysis submitted to the EPA in February 2018 provides demonstrable data to produce an emissions factor approximately 25 percent of the factor the EPA used in its estimate.

Regarding the number of valves, the EPA's determination in its model facility that a low production wellsite includes 100 valves does not reflect all areas in the country that would be affected by these regulations, particularly as existing sources are affected in future regulatory actions.

i. ***If these assumptions are incorrect, it significantly changes the cost-effectiveness assumptions of the EPA fugitive emissions program.***

Without addressing all of the assumptions in the EPA Model Low Production Well plant that are called into question by the additional information in the material that the Independent Producers acquired from the 13 states where we were able to get limited information, the information above on valves and the questionable emissions factor alone change the nature of the EPA's cost-effectiveness analysis.

For example, if the number of valves used for the natural gas Model Low Production Well plant is changed to 20 and the API emissions factor for valves is used to calculate the fugitive emissions program's cost-effectiveness using the EPA spreadsheet provided in the Docket[12], cost per ton of recovered methane increases by a factor of about 2.5. More tellingly, the amount of recovered methane would be estimated at 0.092 mcfd. It is hard to imagine that this miniscule amount of methane would even be detectable; it is unlikely to even be measurable as additional product.

Moreover, these calculations do not address the cost of the EPA proposed program. As we have shown earlier, past history with OGI programs has demonstrated these programs to have been far costlier than the EPA presumed. To put an additional point on it, for the Pennsylvania wells that were identified in this inventory, the operator estimates that the cost of the biennial EPA OGI fugitive emissions program would exceed $800,000 – or $400,000 per year. The average production of those wells is about 6 mcfd.

d. ***Assessing the cost impact on low production wells needs to look beyond the common tests of cost effectiveness in a cost per ton of reduced emissions to address the cost impact in the profitability of these small wells.***

In the context of low production wells, the EPA's analysis of the cost effectiveness of its regulations, as flawed as it may be, also fails – like most cost-effectiveness analyses to address a more critical issue. Cost-effectiveness analyses typically look at the cost per unit of pollutant recovered. For low production wells, wells generally operated by small businesses, there is a remaining significant issue – whether the absolute cost can be absorbed by the operations that are regularly economically challenged.

Not surprisingly, the impact of a fugitive emissions program is significantly different between small and large wells. For the past several years, the EDF has polluted the air with an analysis that it developed showing that a variety of methane controls are cost effective when that is not the case. The EDF states these controls only cost a few cents.

---

[12] Proposed_Rule_OOOOa_TSD_Section_2_-_OGI_Compressor_Model_Plant_Costs

The problem is that the EDF's analysis is flawed and, when the average low producing well produces 22 mcf per day, a few cents per mcf is highly significant. Moreover, the economic assumptions can be as significant as the emissions assumptions. In the Reconsideration Rulemaking, the EPA indicates that it uses a natural gas value of $3.42/mcf. This amount may reflect current natural gas prices at a time where storage limitations and high demand have driven prices higher. However, it fails to reflect that prices in the past several years have been well below this level. In fact, in the past two years, national natural gas prices have triggered the Marginal Well Tax Credit with the Internal Revenue Service calculating that the average price in 2016 was $2.38/mcf and in 2017 was $2.17/mcf. Moreover, producers do not receive the full value of the sales price; they must pay royalties and taxes that reduce the amount received by about 25 percent. Using the IRS average value for those two years ($2.22/mcf), the producer would then receive about $1.67/mcf for any recovered gas.

The EPA's Model Low Production Well analysis calculates that about 280 mcf/yr are emitted and 30 percent is recovered by its LDAR program – 84 mcf/yr. We believe this determination is too high, that API's emission factor is more accurate. Using the high valve count that the EPA assumes for its model well and the API emissions factor yields a recovery amount of 44 mcf/yr. It should be noted that this amount is about 0.12 mcfd and one has to raise a question of whether this amount can even be found or will show up in the daily production measurements.

Using the more realistic product prices, this presumed recovery adds about $73.50 to the annual income of the Model Low Production Well or about $36.75 to the income of a well. It is noteworthy to point out that even this small recovery may overstate the amount since it is highly dependent on the number of valves at a facility.

The larger question is what impact does this have on a low producing well. Using the cost information above, the average low producing well (22 mcfd) would receive daily income of $36.75 ($13,400 per year).

It is difficult to determine operating costs but the EIA released a report in March 2016, *Trends in U.S. Oil and Natural Gas Upstream Costs,* which assessed a wide range of costs and looked at several production areas. One of its evaluations addressed operating costs in the Marcellus play – the world-scale natural gas play in the northeastern states. The report estimated that Marcellus operating costs range from $12.36/BOE to $29.60/BOE. Using the standard 1 BOE = 6 mcf conversion, it produces operating costs ranging from $2.06/mcf to $4.93/mcf. Applying these costs to the average low producing well results in a daily cost range of $45.32 to $108.46.

Consequently, the average low producing well would have to have a natural gas price in the range of $2.06/mcf to $4.93/mcf to break even. In Pennsylvania, where the average low production natural gas well produces closer to 6.0 mcfd and the typical wellsite is one well rather than two, the challenge is even greater. Income would be about $10.00/day with operating costs in the range of $12.00 to $29.00 daily. In this difficult financial situation, the application of the EPA LDAR program is a far more significant factor than the EPA has presumed in its analysis, given that the amount is essentially unmeasurable.

Clearly, there are many factors that come into play in this analysis – price of natural gas, cost of the LDAR program, operating costs. The fundamental point is that an LDAR program that *may* be justified for large producing wells will have a very different impact on small ones. The EPA should develop a methodology that reflects these differences and it has not.

4. **The DOE has announced a research program to determine more accurate assessments of low production well emissions.**

On October 23, 2018, the DOE, Office of Fossil Energy ("FE"), announced a research program to address low production (marginal) well methane emissions. The announcement stated:

> The U.S. Department of Energy's (DOE) Office of Fossil Energy (FE) has approved an unsolicited proposal, titled *Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells*, received from GSI Environmental Inc. (GSI). The data collected from well sites in basins across the United States will help address critical knowledge gaps and support best management practices that are appropriate for marginal wells.
>
> This effort complements related DOE research and analysis projects conducted by the National Energy Technology Laboratory (NETL) to improve understanding of methane emissions and identify potential reduction strategies that can improve the operational efficiency of the Nation's natural gas production and delivery systems.
>
> In June 2016, the U.S. Environmental Protection Agency (EPA) published a final rule in the Code of Federal Regulations to amend the New Source Performance Standards at subpart OOOO, and finalize new standards at subpart OOOOa to reduce methane emissions from new and modified oil and gas facilities. The updated standards included requirements for marginal well sources—oil wells that produce less than 15 barrels per day or gas wells that produce less than 90,000 cubic feet per day—which were not previously addressed.
>
> EPA's decision was based on limited data. The Agency had presumed emissions from marginal and non-marginal well sites were comparable, but that conclusion was derived from data amassed from studies employing a wide variety of technical approaches, none of which were designed to assess emissions specifically from representative populations of marginal well sites.
>
> As part of an ongoing regulatory review and reconsideration process, on September 11, 2018, EPA issued proposed targeted improvements to the 2016 standards that aim to streamline implementation, reduce duplicative EPA and state requirements, and decrease unnecessary burdens on domestic energy producers. The Agency continues to review other aspects of the 2016 rule that could be the subject of future rulemaking.
>
> While the costs of regulatory compliance impact all producers, small independent oil and gas producers who operate many of the over 700,000 marginal wells that dot the United States could be disproportionately impacted, with associated economic impacts to energy production, states, and communities.

> Recognizing these challenges, GSI proposed to collect and evaluate representative, defensible, and repeatable data from each type of well (marginal vs. non-marginal, oil vs. natural gas). This data, together with data from existing sources, will be compiled, evaluated for usability and representativeness, and analyzed to answer two key questions:
>
> - What conclusions can be reliably drawn regarding the relative methane emissions among significant marginal and non-marginal well site populations based on existing available information?
> - What are the key gaps in understanding the relative frequency and magnitude of emissions from marginal vs. non-marginal well sites?
>
> Once these questions are addressed, GSI will develop a focused and detailed scope of subsequent field investigations, as appropriate, to address critical data gaps. Study conclusions will also focus on identification and implementation of appropriate best management practices, so that the United States can continue to rely on traditional oil and natural gas resources for clean, secure, and affordable energy while enhancing environmental protection.[13]

This DOE study provides the EPA the opportunity to do what it should have done as it initially developed Subpart OOOOa – collect direct emissions data on low production wells. This data would allow the EPA a baseline that shows the distinctions between large wells and low production wells and the differences that may exist between types of wells and between production regions.

The EPA should embrace this DOE action.

5. **The EPA should make the following changes to the low production well regulations.**

First, the EPA should retain a low production well distinction in the regulations. Regulations designed for large high production wells do not function appropriately for low production wells averaging 2.6 B/D of oil or 22 mcfd of natural gas.

Second, the EPA should restructure the regulation to provide that as wells decline to the low production well threshold, these wells would move into the low production well requirements.

Third, the EPA should use the U.S. Tax Code definition of stripper wells as the low production well definition. Both the Tax Code definition and the proposed Subpart OOOOa definition use the same 15 B/D BOE basis. However, the Tax Code interpretation is well understood by both producers and federal regulators. Its use would prevent litigation over interpretation of the new Subpart OOOOa language. The EPA can address enforcement and compliance concerns by establishing an initial production threshold that would trigger a one-year

[13] https://www.netl.doe.gov/node/5775

period to determine whether a well is a low production well or not. The current proposal using production after 30 days does not reflect the realities of natural production declines.

Fourth, the EPA should await the results of the recently announced Department of Energy *Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells* project to develop low production well regulations, if any are cost -effective or appropriate given the low emissions from low production wells. The EPA's current use of available data that was never taken with the intent of being used for low production well regulation is inappropriate. The database is too small and, more importantly, too anecdotal to be used for nationwide regulations of the diverse population of low production wells. The EPA should follow the path that it took with regard to a fugitive emissions program in the October 2016 CTG for existing oil and natural gas production facilities in ozone nonattainment areas. In that action, the EPA deferred the institution of a fugitive emissions program until an undefined future date. Given that the results of the DOE project are essential to developing sound regulations, if any are justified, this approach would be consistent with the CTG decision.

6. **The EPA should exempt booster compressors associated with low production wells.**

A forgotten but very susceptible piece of equipment often necessary for gas production from low producing wells with low pressure reservoirs is the booster compressor. There are many situations in the Appalachian Basin as well as other basins, where a booster compressor managed by small operators is necessary to move natural gas from a low pressure well or wells into higher pressure gas flow lines. Often located at or near a wellhead, these booster compressors operate with suction pressures near if not below atmospheric pressure and discharge pressures no higher than 100 psi. The Subpart OOOOa requirement for quarterly fugitive emission surveys with very expensive optical gas imaging equipment can make the use of a booster compressor uneconomical, and leave large portions of a small gas well's otherwise producible reserves in the ground. A picture of a typical booster compressor is below:

The potential to emit fugitive emissions from a booster compressor is very small. At the pressures they operate, the suction side, operating near atmospheric pressure, has little potential to leaks and the discharge side usually has no more than a fitting connecting the compressor to the flowline. Again, booster compressors have very few connections that could leak. Reciprocating compressors, even those used as booster compressors, regulated under Subpart OOOO, are already required to have the rod packing replaced every five years.

Booster compressors should be treated as wellhead equipment for low producing gas wells sufficing to have periodic audio, visual, and olfactory ("AVO") surveys that can be done by small operators, and eliminate the burdensome and expensive optical imaging surveys and recordkeeping that is typically already done at large compressor stations.

III. SUBPART OOOOa STORAGE TANK COMMENTS

A. Background/Proposal

In the reconsideration amendments, the EPA has proposed to change how operators calculate potential emissions and applicability of the storage vessel requirements under the rule. The EPA also proposes to impose additional recordkeeping and reporting requirements related to the applicability determination for both affected and non-affected storage vessels. Specifically, the EPA proposes to:

- Limit the circumstances and operational configurations operators may use to average potential emissions across a tank battery for purposes of determining applicability of a particular storage vessel.

- Revise the definition of "maximum average daily throughput" to require that operators use only the days that production is actually sent to a particular storage vessel during the 30-day evaluation period to calculate maximum average daily throughput for the storage vessel.

- Impose additional limits and criteria on what constitutes a "legally and practically enforceable limit" for purposes of determining storage vessel potential to emit ("PTE").

- Require additional recordkeeping for both affected and non-affected facilities related to storage-vessel applicability determinations.

The EPA's proposed reconsideration amendments present a number of technical and practical concerns. While the EPA claims that some of these changes are mere "clarifications," The Independent Producers have significant concerns because the EPA's proposals represent a departure from the prior EPA statements and practice and raise concerns related to retroactive application and enforcement. Accordingly, the Independent Producers provide these specific comments and suggestions on each of the above-described topics.

B. Maximum Average Daily Throughput and Averaging Emissions Across Tank Batteries.

In the proposed reconsideration amendments, the EPA expresses concern that operators have been "incorrectly averaging emissions across storage tanks in tank batteries when determining the potential for VOC emissions."[14] The EPA states that "[d]ividing an entire battery's throughput by the number of storage vessels in the battery would greatly underestimate flash emissions from the first storage vessel connected in series, which is where liquid pressure drops from separator pressure to atmospheric pressure."[15] To attempt to extend regulatory controls over these tank batteries, the EPA proposes to "clarify" how PTE is calculated for different storage-tank configurations and operations. This includes defining when it is appropriate to divide a tank battery's throughput across an entire tank battery to determine PTE for individual storage tanks for Subpart OOOOa applicability purposes. For example, the EPA states that averaging "could be appropriate" where a tank system is configured in parallel with a "splitter system" and all liquids "initially flow in equal amounts" to individual tanks, but it would not be appropriate when tanks are configured and operated with liquid product flowing in series. As a consequence, the EPA proposes including a revised definition of "maximum average daily throughput" that would specify the exact method of calculation required to determine "daily throughput for an *individual* storage vessel over the days that production is routed to that storage vessel during the 30-day evaluation period." Despite the language in the preamble to the proposal, the EPA's proposed definition appears to prohibit averaging of tank emissions in all

[14] 83 Fed. Reg. at 52,084.

[15] *Id*. at 52,085.

situations, including those under which the EPA suggests averaging may be appropriate (*e.g.*, tanks configured in parallel).

The Independent Producers disagree with the EPA's contention that under Subpart OOOOa (or its predecessor, Subpart OOOO) operators have been "incorrectly" averaging emissions across tank batteries. Subpart OOOOa currently provides that storage tank PTE "must be calculated using a generally accepted model or calculation methodology."[16] Averaging has historically been and continues to be an acceptable methodology for estimating emissions from storage tanks – particularly from tanks that are part of a controlled tank battery. The Independent Producers also disagree with the technical premise relied upon by the EPA to support its assertion that averaging is categorically inappropriate for certain tank configurations. And finally, the Independent Producers have concerns with the EPA's proposed definition of "maximum average daily throughout" as it appears to categorically prohibit averaging storage tank emissions across a tank battery and also overestimates potential emissions by relying only on the days during which throughput is actually sent to a specific storage vessel. Each of these changes directly conflict with Executive Order 13783, issued by President Trump, which directs the heads of all federal agencies to "review all existing regulations, orders, guidance documents, policies, and any other similar agency actions . . . that potentially burden the development or use of domestically produced energy resources, with particular attention to oil, natural gas, coal, and nuclear energy resources."[17] Here, the EPA proposes revisions that would significantly increase the burden on domestic producers of oil and gas.

1. **<u>The EPA's proposal to prohibit averaging of throughput across tank batteries inappropriately ignores fundamental operational processes.</u>**

The EPA's expressed concerns about averaging ignore that many new and modified tank batteries not subject to Subpart OOOOa are either: (1) already controlled pursuant to a state requirement; or (2) if uncontrolled, have a system that allows for the build-up of pressure across the head space of the entire tank battery and collection system. *See* Appendix A for examples of diagrams/drawings of sample facilities manifolded together. Though the Independent Producers believe that there is a technical basis for the EPA to allow averaging in both of these scenarios, the Independent Producers understand the EPA's concern that averaging across multiple tanks in a battery may allow certain storage tank emissions to remain uncontrolled. As a result, the Independent Producers proposed that, in order to alleviate the EPA's concern regarding uncontrolled storage tanks, while still acknowledging the technical reality of how tanks' vapors equalize across a tank battery, the EPA allow averaging (regardless of tank configuration) for all storage vessels that share a common vapor space within a controlled tank battery. The Independent Producers believe that such averaging methodologies should be allowed both for initial applicability determinations and for determinations as to whether tank vessels meet the thresholds below which the storage tank requirements in Subpart OOOOa (or Subpart OOOO) apply.

[16] 40 C.F.R. § 60.5365a(e); *id.* § 60.5430a ("*Maximum average daily throughput* means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.").

[17] 82 Fed. Reg. 16,093 (Mar. 28, 2017).

The Independent Producers wish to put a fine point on why the EPA's proposal is not technically valid, why averaging has a sound basis in engineering, and importantly, why averaging actually addresses the EPA's concern about flash emissions. Tank batteries, controlled by a common flare or combustor system or vented through one common pressure relief valve ("PRV") typically share vapor space (the tank volume above the liquid) and joint piping used to collect generated vapors and convey them to the control device. Because the vapor collection piping is typically free of restrictions, vapors flow both into and out of each tank within the battery and into overflow piping on a continuous basis, and vapors will always flow from high pressure areas to low pressure areas when flow is mechanically unrestricted. In this configuration, the flash emissions from the first tank will not be immediately emitted, but will flow into the other tanks and vent line space associated with the battery as a whole until the total pressure in the system exceeds the back-pressure of the flares, control device, or in systems without controls, the pressure relief valve. Only then will the emissions be released from either the pressure relief valve or combusted by the control equipment.

Given that gas is allowed to equalize among the tank vessels in a manifolded system, there is no technical basis for the EPA's concern about emissions from the first storage vessel in the series being underestimated. The EPA inappropriately assumes that emissions in a manifolded system are individually emitted from each tank and that they result only from the oil being produced into that given tank. In reality, for the reasons described above, the vapors being emitted from the tank battery at any point in time may have originated from any tank in the battery.

Based upon the EPA's technical approach in these proposed reconsideration amendments it may be that the EPA misunderstands how these systems typically work. For example, in the preamble to the proposed Subpart OOOO, the EPA stated: "[d]uring times of flash emissions, tanks are designed such that the flash emissions are released through a vent on the fixed roof of the tank when pressure reaches just a few ounces to prevent pressure buildup and resulting tank damage."[18] However, for facilities under the configuration described above, this individual emitting from tank thief hatches does not occur in the manner described by the EPA. Rather, vapor pressure equalizes across the system and emissions are released only when the pressure in the battery as a whole exceeds the backpressure of the PRV or the emissions proceed through the combustion device: whether emissions will or will not occur is dependent on the capacity of the entire vapor control system, not the individual storage tank. Thus, contrary to the EPA's suggestion in the proposed reconsideration amendments, dividing an entire tank battery's throughput by the number of storage vessels in the battery would be an appropriate and acceptable methodology in cases where all vessels in the tank battery share vapor space, emissions generated in one vessel equalize into the other vessels in the tank battery, and emissions are eventually controlled by the same control device or released through common PRVs. In this context, it is irrelevant whether the tanks are operated in series or in parallel, because it is not the throughput of the liquids through any single vessel within the system that determines potential emissions, but a number of other factors, including the operation of the combined vapor control system for the integrated tank battery. Accordingly, the determinant

[18] 76 Fed. Reg. 52,738, 52,764 (Aug. 23, 2011).

factor for allowed averaging across multiple storage vessels within a system is shared vapor space, rather than the EPA's proposed focus of liquid filling configuration.

2. <u>The EPA's proposal to eliminate averaging is inconsistent with recent consent decrees related to the design and operation of vapor control systems on storage tanks.</u>

The Independent Producers' technical explanation above, on how emissions are released from storage tank batteries, comports with the EPA's interpretation in recent enforcement cases. In the past several years, the EPA has entered into a number of consent decrees related to the design, and operation and maintenance of vapor control systems on storage tanks. In each of those consent decrees, the EPA acknowledges (and in fact demands) that the operator consider the vapor control system as a whole in determining how to design to avoid emissions from storage tanks. Specifically, the consent decrees typically define a vapor control system in the following manner: the system used to contain, convey, and control vapors from one or more storage tank(s) (including flashing, working, breathing, and standing losses), as well as any natural gas carry-through to storage tanks. A vapor control system includes a tank system, piping to convey vapors from a tank system to a combustion device and/or vapor recovery unit, fittings, connectors, liquid knockout vessels or vapor control piping, openings on storage tanks (such as thief hatches and any other pressure relief devices, and emission control devices). Through this definition, the EPA makes clear that it treats the vapor control system as one system, specifically a system that includes all storage vessels sharing a common vapor manifold. The EPA's proposal that prevents averaging across individual tanks even for controlled tanks and instead requires a theoretical assessment of emissions from individual tanks, even where they share a common vapor space, is entirely inconsistent with the underlying theory of the EPA's consent decrees and their treatment of vapor control systems – particularly for facilities with existing control requirements under state or permit requirements.

C. The EPA's Concern About the Amount of Storage Vessels Subject to Subpart OOOOa is Overstated and Unfounded.

As support for its position that operators have been "incorrectly averaging emissions across storage tanks," the EPA states that inspection data and compliance reports for the 2016 Subpart OOOOa indicate that operators reported "fewer than expected number of reported storage vessel affected facilities."[19] But the number of storage vessels subject to Subpart OOOOa is not in fact surprising and presents no basis for concern.

In the preamble to the proposed Subpart OOOO, the EPA clearly expressed that it originally developed the storage tank requirements because it "believe[s] it is important to control tanks with significant VOC emissions under the proposed NSPS."[20] The EPA's recently expressed concerns about the number of tanks reported under Subpart OOOOa seem to be focused on an attempted regulatory expansion with no corresponding environmental benefit. The interpretation ignores that a significant number of states already have storage tank control requirements that are similar to or even more rigorous than those presented by Subpart OOOO or

[19] 83 Fed. Reg. at 52,084.

[20] 76 Fed. Reg. at 52,763.

OOOOa. Those many programs require control of storage tanks and therefore provide operators with an enforceable limit on the VOC emissions from those storage tanks. As a result, it should be expected that facilities complying with a state control requirement would not also be subject to potentially duplicative, or even inconsistent, requirements under Subparts OOOO or OOOOa. In fact, the EPA has previously acknowledged that the focus and intent of the Subpart OOOO and OOOOa storage tank provisions was to ensure that storage tanks *not otherwise subject to state control requirements* are subject to a corresponding federal requirement to control VOC emissions.[21] The EPA's statement now, that operators reported fewer than expected storage vessels, simply means that the EPA's estimates were not entirely accurate at the forefront; a fact that is far from surprising given the complex nature of the issue.[22] In fact, even if operators followed the EPA's proposed methodology for calculating emissions from individual storage vessels, the EPA may not see as marked an increase in storage vessels subject to NSPS OOOOa as it thinks. As noted elsewhere, following the EPA's methodology for calculating emissions from individual storage tanks would potentially result in many instances where the first storage vessel in a battery is subject to Subpart OOOOa but none of the remaining storage vessels are subject. Thus, the actual number of tanks reported under Subpart OOOOa might not increase to the extent the EPA expects.

Finally, and as noted above, because these storage tank systems are controlled and function as one vapor control system, there is no basis to require companies to consider individual emissions from individual tanks as such a scenario is inconsistent with the way these facilities are operated.[23] Thus, the EPA's comment that companies have been incorrectly averaging is inaccurate and misleading. As the EPA notes in the Reconsideration Rulemaking, "[o]perators should ensure that the determination of the potential for VOC emissions reflects each storage vessel's actual configuration and operational characteristics."[24] However, the EPA fails to do exactly that when it ignores that many of these vessels share a common vapor space and either have a pressure relief valve or control device that equalizes pressure across the entire

---

[21] *See* EPA Letter to Matthew Todd, 5 (Sept. 28, 2013) (acknowledging that the EPA's original estimates for the number of affected facilities under Subpart OOOO excluded facilities already subject to state emission-control requirements for storage tanks); 78 Fed. Reg. 22,126, 22,130 (Apr. 12, 2013) (subtracting from estimated number of affected facilities storage tanks in the eleven states with existing control requirements).

[22] *See, e.g.*, 78 Fed. Reg. at 22,130 (revising original Subpart OOOO estimates for storage tanks from 304 tanks per year to approximately 11,000 per year).

[23] Importantly, for controlled tank batteries, improvements to storage tank design, operation and maintenance have been adopted by operators as new information about those facilities has been identified, including through the EPA's September 2015 Compliance Alert. Though these issues are not relevant to the applicability of the storage tank requirements in Subpart OOOOa to storage vessels, these improvements render some of the EPA's historic concerns less realistic as they help ensure that emissions remain in the vapor collection system until combusted by emissions control equipment. Significant work has also been done on the functionality and operation of thief hatch and PRVs, and new thief hatch and PRV designs allow for even greater set pressures, thus accommodating higher tank vapor pressures and reducing fugitive emissions when compared to similar equipment just a few years old. The net result is an overall improvement in storage vessel vapor collection and control system operation that keeps more vapors in the system with more efficient control of the entire tank battery – especially during maximum throughput conditions – and that demonstrates a concerted effort by industry to address the concerns and issues with storage tank emissions first raised by the EPA in its September 2015 Compliance Alert.

[24] 83 Fed. Reg. at 52,085.

battery. The EPA's failure to acknowledge these key operational characteristics is particularly egregious for tanks that are already controlled.

D. The EPA's Proposal to Calculate Individual Tank Emissions Based Upon Throughput to Each Individual Tank is Technically Flawed and Overly Burdensome.

Instead of averaging throughput and emissions across a tank battery, the EPA now contends that operators should be determining throughput for each individual storage vessel. The EPA proposes two separate methods for accomplishing this feat: (1) actively measure daily throughput to each individual tank via auto-gauging or manual gauging;[25] or (2) determine for each loadout period, the highest average daily throughput for each storage vessel.[26] For the second method, where tank throughput is not monitored daily, the EPA suggests the following procedure for determining individual tank throughput: (1) measure the liquid height in the storage vessel at the start and completion of loadout of liquids from the storage vessel; and (2) divide the volumetric throughput calculated from the change in liquid height over the number of days in the production period.[27] The EPA defines a "production period" as the date "production begins to be routed to a storage vessel" until the date "throughput is routed away from that storage vessel or when a loadout occurs from that storage vessel."[28] If a tank system undergoes multiple loadouts during the thirty-day evaluation period, operators must use the maximum of the production period average daily throughput values to calculate the potential emissions from the individual storage vessel.[29]

The EPA's proposal is overly burdensome, contradicts "generally accepted" methods to calculate emissions, and ignores the technical complexity and feasibility of such an assessment. First, the EPA assumes that many operators have a readily available mechanism for determining the production within each tank on a daily basis. Equipment for determining the throughput of individual tanks is not available in all or even most instances and does not reflect a generally accepted method for evaluating production to or emissions from individual storage vessels. Whether a mechanism for determining daily production from each tank exists depends upon a number of factors, including operational configuration and commercial considerations. In most instances, there is no need to assess the production in any individual tank as liquids are not removed until the capacity of the tank battery as a whole reaches certain levels. This is particularly true at facilities that utilize lease automated control technology ("LACT") systems that automatically release liquids into a gathering pipeline upon reaching certain thresholds in the storage vessel connected to the LACT unit. Even at facilities that are loaded out by truck, there is no operational basis for allocating production from the entire battery to individual tanks.

---

[25] As to this first method, the Independent Producers also want to clarify that the EPA's proposed language in the preamble that refers only to "automated gauging" generally, should be more specifically limited to scenarios where operators employ *daily* gauging (whether manual or automated). The Independent Producers stress, however, that regardless of the type of gauging employed, this should not be required on a per-tank basis.

[26] *See* 83 Fed. Reg. at 52,084.

[27] *Id.*

[28] *Id.*

[29] *Id.*

Requiring operators to undertake such granular and nuanced information for tank batteries with existing controls already in operation provides no environmental benefit and does not comport with generally accepted methods for operating these systems.

Finally, the EPA appears to assume that the emission factor will be the same for all of the production in a storage tank battery – regardless of whether the production is contained in the first tank in a series or the last. Such an assumption is inconsistent with the EPA's own statements in the preamble that the majority of flash emission potential is created due to the initial pressure drop when production is dumped from the separator to the first tank. It is also inconsistent with the technical reality that applies to these systems. Tank battery vapors are generated in three ways: thermodynamic flashing when the liquids change from higher to lower pressure; working loss when liquids flow into the storage vessel displacing vapors within the vessel; and breathing loss due to heating and cooling cycles. Under the EPA's theory, the remaining tanks in a tank battery are limited to working and breathing loss as production is transferred from one atmospheric tank to another. The reality, however, as described above, is that when tank batteries share a common vapor recovery system and control, the vapors generated by the initial pressure differential equalize across the connected vessels because the low restriction allows the vapor to flow more easily to the nearby tanks than to the distant flare(s) or combustor(s). Thus, the vapors – and emission potential – equalize throughout the entire tank battery despite being generated in the first tank receiving liquids. Accordingly, under this type of configuration, the most accurate way to determine each individual tank's PTE is to average throughput and PTE across the tank battery.

E. The EPA's Proposed Methodology Could Produce the Absurd Result that Only One Tank in a Manifolded Series of Tanks is Subject to Subpart OOOOa.

The EPA's proposal to calculate PTE based on each individual vessel in a battery could produce a situation where only one tank in a battery is subject to Subpart OOOOa. And in fact, because the emission factor for each tank in a battery reduces dramatically as production is routed to each successive vessel, the EPA's proposal makes this scenario likely: the first tank in every battery would be subject to the rule while the remainder of the battery is exempt. Under the EPA's proposed scenario, all flash gas attributable to a volume of oil or condensate would be calculated as being emitted from the first tank in series. Subsequent tanks would have no flash gas emissions because the oil or condensate will have depressurized from separator pressure to atmospheric pressure in the first tank. The only emissions from subsequent tanks in series would be due to working and breathing losses. In many cases, particularly for older batteries with lower throughput, working and breathing losses alone will not exceed the applicability threshold of 6 tons VOC per year per tank. Under this scenario, only one tank in a multi-tank battery would be subject to the requirements of Subpart OOOOa – even though the vapor control system for that battery captures and controls emissions from all the tanks in the battery. And operators would have only one tank in a battery subject to Subpart OOOOa's control, design, and recordkeeping and reporting requirements for storage vessel affected facilities, including:

- Route all emissions through a cover and closed vent system to a control device with a 95 percent destruction efficiency.[30]

- Design and certify the closed vent system to ensure "no detectable emissions."[31]

- Conduct periodic olfactory, visual and auditory inspections to ensure no detectable emissions.[32]

- Comply with all applicable recordkeeping and reporting requirements under the rule.[33]

Industry, for the sake of operational compliance, safety, and efficiency, often determines applicability on the basis of averaging throughput across all vessels in a battery when utilizing a single, manifolded collection system feeding a control device, and there is a tremendous net emissions benefit when controlling all tanks in a battery, based on throughput averaging, compared to controlling only one vessel based on individual throughput. Averaging and controlling all vessels in a battery – even if it results in the controlled VOC emissions per vessel being less than 6 tons per year – is far better environmentally than controlling only one Subpart OOOO/OOOOa applicable vessel.

It is ultimately not feasible for operators to comply with the above requirements for a *single* storage vessel. Rather, the EPA has readily admitted that if only a single storage tank in a battery were subject to the Rule, "*the owner or operator would have to vent the entire manifold to a control*."[34] Accordingly, under the guise of a "clarification," the EPA effectively proposes to require operators to control and operate an entire battery as subject to Subpart OOOOa based on the theoretical emissions of the first tank.[35] And the EPA has entirely failed to take this result into account in its estimates of the amount of affected facilities that would be subject to the rule and the cost-benefit analyses used to support the rule.

F. The EPA's Proposal to Only Include Days in Which Tanks Received Production Would Overstate Potential Emissions and Would Create an Unnecessary and Overly Burdensome Recordkeeping Requirement.

The EPA proposes that "production to a single storage vessel must be averaged over the number of days production was actually sent to that storage vessel, rather than over the entire 30 days."[36] For example, the EPA states that "if a storage vessel receives production on 22 of the 30

---

[30] 40 C.F.R. §§ 60.5395a(b)(1), 60.5411a(b)-(d), 60.5412(c)-(d).

[31] *Id.* § 60.5411a(c)–(d)

[32] *Id.* § 60.5411a(c).

[33] *Id.* § 60.5411a(e).

[34] EPA, Response to Public Comments on Proposed Rule August 23, 2011 (76 Fed. Reg. 52,738), at 112–13 (emphasis added).

[35] *See* Section II.A–B, D.

[36] 83 Fed. Reg. at 52,084.

days in the evaluation then the maximum average daily throughput is calculated by averaging the daily throughput that was calculated for each of those 22 days."[37] The EPA suggests that it understands this approach would not produce a true average, but that it accurately represents *potential emissions*.[38] This is inaccurate. The EPA's proposed approach fails to account for the fact that maximum well production has a limit based on what the wells can produce, and ignores the fact that the same well production will be routed to different tanks in the battery throughout the 30-day period. In this manner, the EPA's proposal requires operators to count the same throughput multiple times for different tanks, resulting in a value greater than the actual possible total production from the wells. Thus, averaging daily throughput for each individual tank based only on the days the tank actually receives production during the 30-day evaluation period would over estimate the total amount of production that each tank could receive over a 30-day window. And when compounded across multiple tanks and extrapolated across an entire year, this approach would significantly overestimate the volume of flow to the tanks as a whole.

G. The EPA Cannot Apply its Proposed Amendments Retroactively.

Contrary to the EPA's suggestion, its proposed amendments related to storage tank applicability represent far more than a "proposed clarification."[39] Rather, the EPA's proposed amendments represent a fundamental shift in how many operators have interpreted and applied both Subparts OOOO and OOOOa; an interpretation grounded in the language of the regulation and numerous prior statements by the EPA. For this reason, if the EPA retains its proposed amendments regarding the process for determining storage tank applicability (either in part or in full), the EPA should apply the new definitions and interpretations on a prospective basis only.[40]

As a threshold matter, the EPA itself acknowledges in the proposed reconsideration amendments that it was unclear in its prior rulemakings whether operators could average emissions across a tank battery to determine applicability. Specifically, the EPA stated, "[w]hile the EPA was clear that emissions are not to be averaged over the 30-day period, *we were less clear at the time as to what averaging was allowed* when we used the term 'maximum average daily throughput.' Therefore, we propose to further clarify in this notice when and how daily production may be averaged in determining daily throughput."[41] And the rule language itself nowhere states that operators may not average emissions across a tank battery (particularly a controlled tank battery) in order to determine applicability (nor does it line up with the realities of tank batteries that share common vapor control systems, making it all the more difficult to pull this interpretation out of the rule text). The rule language states only that "[t]he potential for VOC emissions must be calculated *using a generally accepted model or calculation methodology*, based on the maximum average daily throughput determined for a 30-day

---

[37] *Id*.

[38] *Id.* (emphasis added)

[39] 83 Fed. Reg. at 52,085.

[40] *See Georgetown Univ. Hosp. v. Bowen*, 821 F.2d 750, 757 (D.C. Cir. 1987) (The Administrative Procedure Act "requires that legislative rules be given future effect only").

[41] 83 Fed. Reg. at 52,084 (emphasis added).

period."[42] Thus, by acknowledging that most operators have chosen to average emissions across tank batteries, the EPA is acknowledging that this is a generally accepted calculation methodology and that it was reasonable for operators to interpret the regulation in this manner.[43] Accordingly, the Independent Producers request that if the EPA retains any portion of its proposed amendments regarding the methodology for determining storage tank applicability, the EPA should make clear in the final rule that those regulatory changes apply on a prospective basis only to sources new or modified after a date certain. Of note, the proposal open for comment addresses only revisions to Subpart OOOOa and does not purport to revise the language of Subpart OOOO. However, because of the similar (and in many cases identical) nature of the language within Subparts OOOO and OOOOa, revisions to Subpart OOOOa could be interpreted to require similar application of Subpart OOOO. All of the concerns related to retroactivity of Subpart OOOOa apply equally to Subpart OOOO and present an even greater legal challenge given that Subpart OOOO is not open for revision at this time.

Limiting any adopted amendments to prospective application is particularly important in this instance because the evaluation period for many facilities potentially subject to the rule would have occurred during the first 30-day production period. Thus, to comply with the EPA's proposed change, operators would need to have records for throughput to each individual tank (not battery) for the first 30-day period of production for each storage vessel dating back to September 2015 for Subpart OOOOa and to August 2011 for Subpart OOOO.[44] Given that operators reasonably and rationally interpreted the rule to allow them to apply an averaging methodology for determining storage tank emissions, it would be unrealistic to now require operators to have the type of records the EPA enumerates in the proposed reconsideration amendments.[45] Furthermore, the EPA cannot retroactively apply the new or modified source standards to existing sources through a change in interpretation without establishing a new date after which that interpretation would apply to new and modified sources.

H. Definition of Legally and Practically Enforceable Limits.

The EPA proposes to impose additional limits on what constitutes a "legally and practically enforceable limit" for purposes of determining storage tank PTE.[46] Specifically, the EPA purports (through language in the preamble of the proposed amendments alone) to require that "any limit on capture and control efficiency from storage vessels must include sufficient

---

[42] 40 C.F.R. § 60.5365a (emphasis added).

[43] *See Gen. Elec. Co. v. U.S. E.P.A.*, 53 F.3d 1324, 1329 (D.C. Cir. 1995) (noting that in determining whether a "regulated party received, or should have received, notice of the agency's interpretation," courts will look first to the plain language of the regulation).

[44] Even if the EPA were to adopt some or all of its proposed amendments to Subpart OOOOa, the Independent Producers would oppose similar revisions to Subpart OOOO. But the Independent Producers also acknowledge the reality that the EPA's proposal calls into question industry's interpretation of the relevant provisions under both rules.

[45] *See* 83 Fed. Reg. at 52,084 (describing proposed methodology for determining individual tank throughput); *id.* at 52,085 (proposed recordkeeping requirements for demonstrating applicability determination).

[46] *Id.*

monitoring to timely identify and repair emissions from storage vessels."[47] This language raises significant concerns and represents a material departure from longstanding EPA practice. Specifically, the EPA's proposal to put additional parameters on what constitutes a "legally and practically" enforceable limit: (1) conflicts with prior EPA statements during Subpart OOOO rulemakings; (2) conflicts with traditional EPA practice to defer to states to determine appropriate mechanisms for limiting PTE; (3) raises concerns about how this new interpretation/approach would apply in the Title V and New Source Review ("NSR")/Prevention of Significant Deterioration ("PSD") context where operators are relying on the same control requirements to limit their PTE; (4) raises significant concerns about retroactive application; and (5) ignores that the LDAR requirements for fugitive components under Subpart OOOOa are not tied to storage-tank applicability and apply regardless of whether a storage tank is an affected facility under the rule.

The EPA suggests that its proposal to impose additional criteria on what constitutes a legally and practically enforceable limit is grounded in the EPA's requirement that enforceable limits meet "certain enforceability criteria."[48] The Independent Producers disagree that the EPA's enforceability criteria requires the heightened standard proposed by the EPA. The EPA first announced its "enforceability criteria" in 1995.[49] The 1995 Guidance enumerates only three enforceability criteria for permit conditions: "(1) a technically accurate limitation and the portions of the source subject to the limitation; (2) the time period for the limitation (hourly, daily, monthly, annually); and (3) the method to determine compliance including appropriate monitoring, record keeping and reporting."[50] And "for rules and general permits that apply to categories of sources, the EPA established that "practical enforceability additionally requires that the provision [1] identify the categories of sources that are covered by the rule; [2] where coverage is optional, provide for notice to the permitting authority of the source's election to be covered by the rule; and [3] recognize the enforcement consequences relevant to the rule."[51] Since the EPA promulgated the 1995 Guidance, the EPA has consistently interpreted this provision to mean that state regulations that are "enforceable as a practical matter," will be considered sufficient to limit a facility's PTE.[52] This means that the permit conditions or regulations must include "monitoring, recordkeeping, and reporting requirements sufficient to enable regulators and citizens to determine whether the limit has been exceeded and, if so, to take appropriate enforcement action."[53] Here, the state regulations and permits relied upon by

---

[47] *Id.*

[48] *Id.*

[49] *See* EPA, Memorandum on Options for Limiting the Potential to Emit (PTE) of a Stationary Source Under Section 112 and Title V of the Clean Air Act (Act) (Jan. 25, 1995).

[50] *Id.* at 6.

[51] *Id.*

[52] *See In the Matter of Hu Honua Bioenergy, LLC*, 2016 WL 7489673, at *20; EPA, Interim Policy on Federal Enforceability of Limitations on Potential to Emit, 3 (Jan. 22, 1996) ("[T]he term 'federally enforceable' should now be read to mean 'federally enforceable or legally and practicably enforceable by a state or local air pollution control agency.'").

[53] *Hu Honua Bioenergy, LLC*, 2016 WL 7489673, at *20 (internal quotations omitted).

industry in calculating PTE for purposes of Subpart OOOO and OOOOa more than satisfy this standard.

For example, in October 2013, following the EPA's publication of Subpart OOOO, the Colorado Department of Public Health and the Environment ("CDPHE") published internal guidance on the "Interpretation of 'Practically Enforceable' Limits for Storage Vessels Addressed under Subpart OOOO ("CDPHE Guidance"). Under the CDPHE Guidance:

> [A]n oil and gas storage vessel with an associated and properly operating flare or other commonly-recognized emission control device may take credit for the emissions reductions achieved by that control device when evaluating if the storage vessel is an "affected facility" where the control device is required through: (1) Colorado Air Quality Control Commission regulations (i.e., Regulation No. 7 Sections XII or XVII); (2) Colorado Oil and Gas Conservation Commission (COGCC) regulations; (3) Enforcement documents, such as a Compliance Order on Consent issued by an air authority such as the Division or EPA; (4) Federal regulations (*i.e.*, NSPS or MACT); or (5) Local air quality requirements or regulations.[54]

This interpretation was the correct one: all of these regulatory mechanisms require the continuous control of emissions through an emission control device and impose recordkeeping and reporting obligations on the operator to allow the agency to determine compliance. Importantly, operators relied on this regulation based on this interpretation. Similarly, relying on the EPA's consistent interpretation of "legally and practically enforceable limits," operators around the country rationally interpreted Subparts OOOO and OOOOa to allow them to account for state regulations and permit conditions requiring the control of storage tanks when calculating PTE for purposes of Subparts OOOO and OOOOa applicability. In fact, as discussed above, in the preamble to the proposed 2013 amendments to Subpart OOOO, EPA evaluated eleven states with significant oil and gas production to determine which had storage tank control requirements that operators could take into account when determining PTE: Alaska, California, Colorado, Kansas, Louisiana, Montana, North Dakota, New Mexico, Oklahoma, Texas, and Wyoming.[55] Based on its evaluation of these regulations, the EPA subtracted storage vessels in states with storage tank control requirements "from the overall count of storage vessels that would be subject to the final rule."[56] Since that evaluation, additional states have developed control requirements that appropriately establish legally and practically enforceable limits. Thus, the EPA's new approach in the proposed reconsideration amendments not only conflicts with its traditional and consistent practice; it also threatens to subject existing sources to performance standards without sufficient notice.[57]

The EPA's suggestion that existing state regulatory programs and permit conditions no longer meet the definition of "legally and practically enforceable" also casts uncertainty on other

---

[54] CDPHE Guidance at 1.

[55] *See* 78 Fed. Reg. at 22,130.

[56] *Id.*

[57] *E.g.*, *Gen. Elec. Co.*, 53 F.3d at 1329.

CAA programs. Operators currently rely on the same regulations and permit conditions used to restrict PTE for Subparts OOOO and OOOOa to remain a synthetic minor under the EPA's Title V and PSD/NSR programs. The EPA's proposal thus causes confusion and casts doubt on thousands of permits under these programs around the country.

Based on the above, the Independent Producers suggest that EPA remove its proposal to impose additional parameters on enforceable limits under Subpart OOOOa and, consistent with longstanding practice, continue to defer to states to determine which of their programs satisfy the standard. However, in the alternative, if the EPA chooses to retain its proposal to redefine what constitutes an enforceable limit under Subpart OOOOa, the EPA should: (1) apply its new interpretation prospectively; (2) offer detailed guidance to operators and states on what constitutes a legally and practically enforceable limit under the rule; (3) clarify the effect of its new interpretations in regard to other CAA programs; and (4) give states sufficient time to revise their programs and permits before making this portion of the rule effective.

Finally, the Independent Producers emphasize that the EPA's concerns regarding legally and practically enforceable limits for sources potentially subject to Subpart OOOOa are unfounded because the EPA has ignored that Subpart OOOOa requires compliance with its LDAR requirements regardless of whether the requirements related to storage tanks apply. As noted above, the EPA states in the reconsideration amendments that "any limit on capture and control efficiency from storage vessels must include *sufficient monitoring to timely identify and repair emission from storage vessels* to ensure the limit on capture and control efficiency is consistently achieved."[58] Through this language, the EPA appears to be suggesting that legally and practically enforceable limits under state regulations and permits must include requirements similar to those imposed under a leak detection and repair program in order for operators to utilize the controlled PTE in determining applicability of the storage tank requirements in Subpart OOOOa. However, this suggestion ignores that the standards for storage vessels under Subpart OOOOa are focused on the installation of a control device, cover, and closed vent system to reduce VOC emissions from the storage vessel.[59] Another Section, § 60.5397a, imposes leak detection and repair requirements on the affected facility defined as "the collection of fugitive emissions components at a well site."[60] This includes all "valves, connectors, pressure relief devices, open-ended lines, flanges, covers and closed vent systems not subject to § 60.5411a, [and] *thief hatches or other openings on a controlled storage vessel not subject to § 60.5395a*."[61] In other words, storage vessels "not subject" to the control requirements of § 60.5395a – in many cases because they are subject to a corresponding state control requirement – must still implement an LDAR program for fugitive emissions under the rule. Therefore, it is entirely unclear what the EPA hopes to achieve by requiring similar requirements under state programs in order for operators to be able to take those regulations and conditions into account when calculating PTE for purposes of Subpart OOOOa.

---

[58] 83 Fed. Reg. at 52,085 (emphasis added).

[59] *See* 40 C.F.R. § 60.5395a.

[60] *Id.* at § 60.5397a

[61] *Id.* at § 60.5430a (emphasis added).

I. Proposed Recordkeeping Requirements for Storage Vessels.

1. <u>The EPA's enhanced recordkeeping requirements for affected facilities are unduly burdensome and unnecessary</u>.

The EPA proposes a significant number of new recordkeeping requirements – mainly to correspond with the methodology that the EPA now proposes that operators utilize in calculating emissions from individual storage vessels.[62] As noted above in Section III.D, the EPA proposes a methodology of estimating emissions and assessing throughput to individual tanks that is inconsistent with many operators' current practices or has any technical basis. Because each of these recordkeeping requirements implicates operators' ability to generate the information required, the Independent Producers have significant concerns with the records proposed to be maintained.

Of particular note, the EPA proposes that operators document the operational configuration of the tank, including recordkeeping of the specific storage vessel that production was routed to for each day in the 30-day production period. Such a requirement indicates that the EPA fundamentally misunderstands how tank systems function and creates an overly burdensome new record requirement that operators neither maintain nor see any value in maintaining. Importantly, operational configurations of tank batteries are not static and can change (even on a day-to-day basis). The tank that first receives production one day may be the second tank to receive production the next day. Thus, it is not feasible to maintain or track each different configuration or track the days on which a specific configuration was in operation. And there is no value to doing so for controlled tanks that are manifolded together as described above.

Accordingly, consistent with the Independent Producers' Comments throughout, and in Section III.I in particular, the Independent Producers suggest that the EPA remove the proposed recordkeeping requirements to the extent they would require operators to document the operational configuration of the tank or document throughput to individual vessels in a tank battery.

2. <u>The EPA should not impose recordkeeping requirements on facilities not subject to the rule</u>.

In the Reconsideration Rulemaking, the EPA is also soliciting Comments "on specific recordkeeping requirements that would support the applicability determination for each individual storage vessel *regardless of whether that storage vessel is determined to be an affected facility*."[63] According to the EPA, "[t]his is because recordkeeping is necessary to be able to verify that rule applicability was appropriately determined in accordance with the regulatory requirements."[64] Such an approach is entirely inconsistent with traditional NSPS requirements. Operators are required to determine compliance with an NSPS. Operators, upon

[62] *See* 83 Fed. Reg. at 52,085.

[63] 83 Fed. Reg. at 52,085 (emphasis added).

[64] *Id.*

request and in certain circumstances, may be required to demonstrate the basis for their conclusion that a facility is not subject to an NSPS. Operators perform this assessment in some way, shape, or form for every NSPS. However, the NSPS itself – which is only applicable to affected facilities – should not in this one case have an independent recordkeeping requirement applicable to non-affected facilities.[65]

The EPA's proposed amendment could create confusion and raises significant enforcement concerns. Operators will typically look first to the applicability section of an NSPS, and if it is determined that a specific facility is not subject to the rule, they look no further (*e.g.*, into the recordkeeping sections applicable only to affected facilities).

Finally, the EPA's proposal raises concerns about the potential for retroactive application (as discussed in further detail above). The EPA says that it is clarifying a rule that has been in existence for years, but is apparently expecting operators to have records that would demonstrate compliance now with the EPA's new interpretation. At a minimum, if the EPA includes recordkeeping for non-affected facilities (which the Independent Producers believe it should not), then the EPA should clarify in the final rule that this new recordkeeping requirement will apply only on a prospective basis.

IV. AMEL – EMERGING TECHNOLOGY

America is on the cusp of new breakthroughs that can bring dramatic improvements to air quality at lower cost. OGI was an important step toward lower emissions, but far from the last step. Less expensive and more effective monitoring technologies will accelerate the production of clean domestic energy, helping to deliver a healthy environment and a healthy economy. The EPA must revise the AMEL provisions of Subpart OOOOa to unlock the benefits of these emerging technologies.

A. The Independent Producers Support the Options in the Proposed Rule to Use Modeling, to Test Technologies in a Controlled Test Environment, and to Allow Manufacturers/Vendors to Apply for Approvals.

1. Modeling

Independent Producers strongly support the inclusion of modeling, in addition to limited field data, to demonstrate the performance of a specific technology. This is a preferred and recommended option to the onerous requirement to gather 12 months of field data. The 2018 Interstate Technology and Regulatory Council ("ITRC") paper states, "Computer modeling is highly valuable for evaluating emission reduction objectives due to the probabilistic nature of emission rates."[66] The paper also states, that "computer-based modeling, coupled with empirical

[65] *See* 40 C.F.R. § 60.1(a) ("[T]he provisions of this part apply to the owner or operator of any stationary source which contains an affected facility.").

[66] Interstate Technology and Regulatory Council ("ITRC"). 2018. Evaluation of Innovative Methane Detection Technologies. Section 5.2 Design Elements. Methane-1. Washington D.C.: Interstate Technology and Regulatory Council, Methane team. https://methane-1.itrcweb.org

validation of model accuracy, is a potential solution to rigorously evaluate application efficacy under the most likely encountered meteorological and site conditions. [67] The Fugitive Emissions Abatement Simulation Toolkit ("FEAST") model is a virtual gas field simulator that predicts emission reductions of various leak detection and repair programs. An effective demonstration of equivalency could include an empirical evaluation of an application at a structurally complex site such as a gathering compressor station over a time period such as twelve months that assesses performance under a wide range of meteorological conditions. If a computer model can accurately predict the detection limit and response time for different sources as a function of environmental parameters, then a probabilistic model can be used to simulate performance at other sites. This approach could allow a scientifically rigorous determination of equivalency while minimizing the number of sites required for field testing."[68] Additionally, modeling is highly valuable in that it allows for comparison of the "end game" of equivalent emissions reductions, *i.e.* allows for comparison of two approaches/work practices rather than specific technology detection thresholds.

Further, the EPA used modeled simulations when they simulated the frequency and work practice to detect leaks from equipment ("OGI AWP").[69] The EPA used a Monte Carlo model to evaluate and approve the use of OGI as an alternative work practice ("AWP") for fugitive emissions monitoring.[70] "In developing the AWP, the EPA sought to design a program for using the optical gas imaging instrument that would provide for emissions reductions of leaking equipment at least as equivalent as the current work practice. To do so, we used the Monte Carlo model for determining what leak rate definition and what monitoring frequency were necessary for the AWP."[71] At no point in its approval of OGI did the EPA require site-specific modeling.

We strongly urge the EPA to apply the same logic to AMEL equivalence demonstrations. There is no reason why rigorous statistical modeling, combined with real-world field data and thorough documentation and recordkeeping, should not be sufficient for EPA to make a reasoned decision on broadly approving a new technology.

a. Controlled test environment.

Use of a controlled test environment, such as Colorado State University's Methane Emissions Technology Evaluation Centre ("METEC") to gather field data on the performance of various leak detection technologies and compare their capabilities to current approved methods, such as OGI, would greatly streamline the process of determining equivalence, as well as the lengthy CAA Section 111(h) application and approval process. The Independent Producers appreciate the EPA including this option in the proposal and further recommends that a facility such as METEC be recognized by the EPA as a facility where all suitable technologies could be tested for equivalency. The team METEC is currently working to establish a baseline for OGI for this very purpose. In fact, the EPA has funded work at METEC toward developing the

---

[67] *Id.*

[68] *Id.*

[69] Alternative Work Practice to Detect Leaks from Equipment Final Rule, 73 Fed. Reg. 78201 (add date)

[70] 73 Fed. Reg. at 78,201.

[71] *Id.*

baseline for OGI. Testing a new technology against a clear established baseline and following a pre-set methodology for testing would provide consistency and confidence in the process. If manufacturers are aware of the baseline emissions reduction for OGI they would clearly know how their technology must be utilized in an LDAR program to be deemed equivalent. As a result this would streamline the process and allow new technologies to successfully navigate this application and approval process and be deployed faster which, in turn, would result in reducing fugitive emissions faster.

The ITRC paper referenced above supports this concept and states:

> [c]ontrolled releases under field conditions are ideal for systems with emission source objectives because they can assess the accuracy of source quantification and/or localization under realistic meteorological conditions. Long-term testing at field sites allows controlled releases to be tested under a diversity of meteorological conditions. Performing multiple controlled releases under each set of conditions can be used to calculate the probability of detection as a function of emission rates and other relevant conditions such as wind speed.[72]

Therefore, gathering field data at a facility such as METEC would prove extremely useful and could effectively take the place of gathering field data at an active oil and gas well site. The API recommends that testing technologies in a controlled test environment, in addition to modeling, will greatly minimize the field data necessary in order to demonstrate the performance of various technologies and achieve approvals.

b. Vendors/manufacturers as applicants for approval of emerging technology.

Vendors/manufacturers of new leak detection technologies are the experts in this advanced, high tech area and are the appropriate person(s) to apply for approval of a technology to be used in compliance with Subpart OOOOa for methane and/or VOC leak detection and Independent Producers appreciates the inclusion of this language in the proposal.

However, the Independent Producers recommend that the operator <u>not</u> be required to be a party to the application and approval process as well. Although the manufacturer/vendor may need to coordinate with an operator to test their technology in the field and obtain data, oil and gas operators are not in the business of, nor are they likely to have the bandwidth, to develop, test, and obtain approvals for methane leak detection technologies.

B. The EPA Should Allow for <u>Basin-Wide</u> Approvals of Emerging Technology for Use in Complying with the Leak Detection Requirements in the Rule

One of the Independent Producers' priority concerns in the proposed Reconsideration Rulemaking is the requirement to apply for the use of emerging technologies on a site-specific level. Outlined below are the technical and legal reasons why this would be an enormous unnecessary burden, not feasible to undertake from an administrative and timing perspective, not effective at showing equivalence to the current method, and will greatly stifle innovation in this

[72] *Id.*

very dynamic area of technological advancement. Numerous technologies are currently being developed and piloted at oil and gas field sites throughout the country. Many of these state of the art technologies in development can detect leaks faster and more efficiently which will enable the operators to make timely repairs resulting in less fugitive emissions, resulting in a win-win for both the operator and the environment. This recommendation has broad support from environmental groups as well as industry.

1. <u>Site specific variables can be addressed in conditions required for the use of the technology.</u>

In the proposal, the EPA states that "we are not changing the requirement that AMEL's be site-specific because we are aware of the variability of this sector and are concerned that the procedures may need to be adjusted based on site-specific conditions (*e.g.*, gas compositions, allowable emission or landscape).[73] There is no logic behind this statement and this reasoning does not withstand scrutiny. First, if a technology is designed to measure methane molecules in the atmosphere, it will measure methane molecules in the atmosphere, plain and simple. It does not matter what the site looks like or what the gas composition is. If there is methane above a certain concentration, the technology should find it; if there is not, it will not.

Further, the EPA can establish clear and consistent parameters under which a technology will be able to detect methane emissions. The approval of the technology could have certain conditions assigned to it that are required to be met in order for the technology to be used at a site, similar to the EPA's technology-based approval for OGI that had minimum/maximum temperatures and minimum/maximum distance parameters required to be present, for example.

Continuous sensors, for example, allow for continuously monitoring a site for leaks and particularly suited for intermittent leaks at very low thresholds. Day or night time is immaterial for detection by continuous sensors. On the other hand, aerial based surveys might have limitations flying at night and may use sunlight as reference and would need to be deployed only during the daytime.

In response to the EPA's mention of landscaping being a site-specific variable, if the landscaping at a particular site is not conducive to the technology employed (*i.e.*, impedes the pathway of the technology to effectively operate, for example) then the technology may not be used at that site. Parameters are required to be met for the proper operation of the specific technology, plain and simple. Again, this could be a condition for the use of a specific technology at a specific site.

In response to the EPA's mention of allowable emissions being a site specific variable, this is completely irrelevant to the case for a site specific approval. Every site has allowable emissions such as some venting that is allowed if under threshold levels. Differentiating allowable venting, for example, from fugitive emissions leaks could arguable be an issue against the approval of any technology but that should not be a reason to disallow approval on a basin-wide level and stifle all development in this important area. An approach where detection may be impacted by allowable emissions may be an approach that is used to direct inspection efforts.

[73] Subpart OOOOa Proposed Technical Revisions, 83 Fed. Reg. at 52,080 (October 15, 2018)

Some technologies could be used as a frequent screening tool and may require the operator visit the site with OGI for example to detect the source of the leak(s). But it would flag the large emitter sites and again, enable the operator to find and fix the largest leaks faster.

In the OGI AWP final rule, the EPA stated, "the standard is an alternative to the existing work practice and maybe used in place of the existing work practice where feasible and whenever the owner or operator chooses to do so."[74] As this language clearly states, OGI received a blanket approval from the EPA but if a particular site did not meet the conditions, then the technology was deemed not feasible that site at that time. Often, Independent Producers' member companies' camera operators determine that they cannot take an accurate OGI survey due to meteorological conditions and they return later when the conditions are within the prescribed OGI parameters.

2. **Basin-wide data is necessary to determine equivalency and receive approval per Clean Air Act 111(h).**

The technologies being developed have different methane sensitivity thresholds and can operate at different frequencies. For example a spectrometer (*i.e.*, laser based technology) mounted on an airplane can scan over an entire basin in days. It could do these fly-overs more quickly and efficiently than a person using a hand held OGI camera on foot at a site and therefore, could have a higher frequency assigned to it and this would be a feasible alternative. The cost benefit analysis of some of these emerging technologies have been shown to be favorable and a preferred option for some member operators.

In the OGI AWP, the EPA states, "[t]he emission control effectiveness of any work practice is a function of both 1) its ability to detect leakage and 2) the frequency of monitoring. An equivalent work practice may require more frequent monitoring, depending on its mass rate threshold for detecting leaks."[75]

If the fly-over technology has a lower sensitivity threshold, it may only find larger leaks, but it could find these larger leaks faster with a more frequent monitoring schedule.

The EPA further states, "[a] more frequent monitoring requirement becomes necessary because higher mass emission reductions from large leaks, found earlier, are offset by some degree by smaller leaks which go undetected."[76] Equivalency in Section 111(h)(3) is discussed simply as "a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such air pollutant [under the current work practice]."[77] Based on this standard in

---

[74] Alternative Work Practice to Detect Leaks from Equipment Final Rule, 73 Fed. Reg. at 78,204 (Dec. 22, 2008). (emphasis added)

[75] Alternative Work Practice to Detect Leaks from Equipment Proposed Rule, 71 Fed. Reg. at 17,404 (Oct. 18, 2008).

[76] *Id.*

[77] 42 U.S.C. § 7411(h)(3).

the statute, larger leaks found earlier and more frequently should reasonably be able to offset smaller leaks that may not be found as timely.

Further, in referring to OGI in the AWP final rule, the EPA stated, "[t]he results show that the AWP will achieve the *EPA's goal of detecting leaking equipment from which the majority of emissions arise."*[78]

Therefore, similar to the EPA's approach in the AWP OGI rulemaking, the EPA should focus on basin-wide (or category-wide) mitigation equivalence, not detection equivalence. For example, a one-time aerial-based survey may not be able to detect emissions with the same sensitivity as ground-based technologies, or detection equivalence, but conducting multiple surveys instead of one would mean that any potential fat-tail emission sources are identified faster than a ground-based method. That means more frequent monitoring may provide mitigation equivalence. Mitigation equivalence can only be achieved across many sites, because of the relatively few sites that produce the bulk of emissions. Further, basin-wide approaches are likely to be more accurate in terms of estimating total emission reductions than individual site estimates, given the high variability in individual site emissions. The emission reductions at any given site may differ greatly, but averaged across thousands of sites, the EPA will be able to understand emission reductions with greater confidence.

The EPA can use statistical models such as FEAST to make data-driven decisions about equivalence. The EPA can then incorporate basin-specific emissions data into modeling to ensure that its emission reduction objectives are being met. Making decisions based on aggregated data reduces the uncertainty that comes with site-specific estimates.

In addition, Independent Producers recommend that the site attributes could be obtained from a small number of <u>representative sites</u> in the basin; then that data, coupled with modeling and testing in a controlled test environment would be adequate to determine if equivalency is achieved.

Further, once a technology is approved to be used in a specific basin, <u>all subsequent sites drilled and constructed in that basin going forward</u> will have the opportunity to use that technology, without going through the onerous Section 111(h) application and, approval process for each new site, or groups of new sites all over again. Again, this is not feasible and would stifle development of leak detection technologies.

Therefore, based on this information and the EPA's logic in this previous OGI AWP rulemaking, a basin wide survey is necessary to have a data set that can be deemed equivalent. And once this technology has been deemed equivalent based on emissions reductions achieved in a specific basin, use of the technology in that basin should be the subject of the application for approval. As explained above, the approval could be granted with conditions that would need to be met at each site prior to the technology being used.

[78] Alternative Work Practice to Detect Leaks from Equipment Final Rule, 73 Fed. Reg. at 78203 (December 22, 2008)

3. **Common sense dictates basin-level approval.**

CAA Section 111(h) requires that an alternative work practice must first be shown to be equivalent, then be subject to a notice and comment period, and possible public hearing. Gathering the field data and performing modeling, and showing equivalence will be a lengthy process, of at least a year of more. Then the notice and comment period will take months; EPA stated in the Subpart OOOOa final rule that they would make a decision within 6 months of close of the comment period.[79] Therefore, realistically, this process would take approximately two years. To do this for every single well site, such as a well or wells on a pad or a centralized tank battery would be ludicrous. Neither the regulated community nor the EPA can manage the crush of applications that will be necessary to adopt new technologies through site-specific approval. It would be outrageously lengthy and absolutely no vendor/manufacturer or operator would undertake this fruitless effort.

One of the Independent Producers member company's operations in the Permian Basin in Texas reported 273 well sites subject to Subpart OOOOa LDAR monitoring for 2018. Going through this Section 111(h) process for each of these sites would take 546 years. And then all over again for the subsequent wells this operator is drilling in the Permian Basin every month (with about 3 wells/pad or well site) and building around 4-6 large centralized tank batteries per year that would also require site-specific approval per the current language in the rule.

Common sense clearly dictates that the EPA reconsider this site-specific approach and approve a basin-wide (or category-wide) approach. Not doing so would stifle innovation in this technologically advanced, dynamic area. The environment would be the loser for the life of this rule if EPA allows only handheld OGI cameras or Method 21, both of which will be outdated technologies in a few years, to detect leaks in compliance with Subpart OOOOa.

4. **CAA Sec. 111(h)(3) does not constrain basin-wide approvals.**

The EPA should provide a procedure for approving an AMEL under Subpart OOOOa for categories of sources, rather than limit an AMEL to an inefficient and unworkable source-by-source application. The structure and language of Section 111 and EPA's decision to allow for similar flexibilities under other CAA provisions confirm that applying an AMEL to source categories is appropriate and lawful.

Section 111 calls on the Administrator to list "categories of stationary sources" that "cause[], or contribute[] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare."[80] The Act then calls on the Administrator to promulgate and subsequently revise every eight years, if appropriate, "standards of performance for new sources within such source category."[81] The Act defines a standard of performance for purposes of Section 111 as:

---

[79] Subpart OOOOa Final Rule, 81 Fed. Reg. at 35,861 (June 3, 2016)

[80] 42 U.S.C. § 7411(b)(1)(A).

[81] *Id*. § 7411(b)(1)(B).

> a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.[82]

In the event it is not feasible to establish such a standard, Section 111(h)(1) authorizes the Administrator instead to "promulgate a design, equipment, work practice, or operational standard, or combination thereof."[83] Section 111(h)(1) does not refer to categories of sources or individual sources, but because a Section 111(h) standard is intended to replace a standard of performance applicable to an entire source category, the logical inference is that Section 111(h) standards also apply to source categories. Section 111(h)(3) provides for an AMEL when:

> after notice and opportunity for public hearing, any person establishes to the satisfaction of the Administrator that an [AMEL] will achieve a reduction in emissions of any air pollutant at least equivalent to the reduction in emissions of such air pollutant achieved under the requirements of [section 111(h)(1)].[84]

On the face of this language, because any AMEL will serve as a replacement for a category-wide 111(h)(1) standard, any demonstration that an AMEL will achieve an emission reduction at least equivalent to a 111(h)(1) standard could reasonably be made on a category-wide basis and be applied to an entire source category.

Section 111(h)(3) also states, however, that once a successful equivalency demonstration has been made, "the Administrator shall permit the use of such alternative by the source for purposes of compliance with this section with respect to such pollutant."[85] This provision's authorization of source-specific AMEL applications should not be interpreted to preclude the EPA's authorization of an AMEL on a source category-wide basis. Indeed, provided an adequate demonstration for a single source within a source category can be made and it can be established that there are no material differences between that source and the other sources in the category that would render the AMEL less than equivalent to a Section 11(h)(1) standard, there is no reason based on the statute to prohibit category-wide application of AMEL. Indeed, any other number of approaches, including a more generalized approach that does not focus on individual sources, for making an adequate category-wide demonstration under Section 111(h)(3) may be available, and EPA should evaluate them on a case-by-case basis.

Allowing for source category-wide AMEL determinations would be consistent not only with the overall structure of Section 111 and its focus on category-wide standards under Sections 111(b) and 111(h)(1); it is also consistent with the limitation prohibiting the EPA from imposing

---

[82] *Id*. § 7411(a)(1).

[83] Id. § 7411(h)(1).

[84] *Id*. § 7411(h)(3).

[85] *Id*.

specific technological emission reduction requirements pursuant to section 111. Section 111(b)(5) states:

> Except as otherwise authorized under subsection (h) …, nothing in this section shall be construed to require, or to authorize the Administrator to require, any new or modified source to install and operate any particular technological system of continuous emission reduction to comply with any new source standard of performance.[86]

Section 111(h)(1) allows the EPA, under limited circumstances, to impose a standard "which reflects the best technological system of continuous emission reduction." Section 111(h)(3) serves as a safety valve on that authority and thereby functions to further the policy set out in Section 111(b)(5). To give full effect to that policy, the EPA should allow for category-wide AMEL demonstrations.

Adopting such an interpretation for Section 111(h)(3) would also be consistent with the policy EPA has adopted for the nearly identical provision in Section 112(h)(3), which authorizes an AMEL under the provisions of the CAA governing national emission standards for hazardous air pollutants. The EPA's regulation implementing Section 112(h)(3) recognizes that the EPA is authorized to approve an AMEL for "source(s) *or category(ies) of sources* on which the alternative means will achieve equivalent emission reductions."[87] Given the similarities between the programs authorized under Section 111 and Section 112 and, in particular, the similarity of Section 111(h)(3) and 112(h)(3), the EPA should adopt its policy of applying an AMEL to source categories for Section 111(h)(3) in the same manner as it has done with respect to Section 112(h)(3).

Moreover, the EPA has adopted similarly flexible approaches under other provisions of the CAA. For example, under the Act's visibility provisions, the EPA must require states to include in their state implementation plans measures reflecting "best available retrofit technology" ("BART") for certain "major stationary sources."[88] The Act further states that BART must control emissions "from such source," and defines BART as taking into account, among other things, "any existing pollution control technology in use at the source" and "the remaining useful life of the source."[89] Despite the focus of the statutory language on determinations for individual sources, the EPA's rules allow the EPA and the states to authorize BART alternatives that can apply to groups of sources and that allow emission averaging across sources, even over wide regions, in lieu of imposing source-specific emission limits or source-specific alternatives to such limits.[90] The courts have consistently affirmed the authority of the EPA and the states in this regard.[91] If alternatives to emission limits (or work practice standards)

---

[86] *Id*. § 7411(b)(5).

[87] 40 C.F.R. § 61.12 (emphasis added).

[88] 42 U.S.C. § 7491(b)(2)(A).

[89] *Id*. § 7491(b)(2)(A), (g)(2).

[90] 40 C.F.R. § 51.208(e)(2).

[91] *See, e.g.*, *Util. Air Regulatory Grp. v. EPA*, 471 F.3d 1333 (D.C. Cir. 2006); *Central Ariz. Water Conserv. Distr. v. EPA*, 990 F.2d 1531 (9th Cir. 1993).

for groups of sources under these provisions are permissible despite the continued references to the term "source," then surely a source category-wide AMEL is permissible under Section 111(h)(3).

In regard to frequency specifically, there is no legal impediment to demonstrating that an AMEL is equivalent to a Section 111(h)(1) standard based on differences between the AMEL and the standard against which it is being evaluated – such as differences in the frequency (*e.g.*, annual, semi-annual, quarterly) over which the monitoring or other requirements must occur. The current regulations for implementing Subpart OOOOa state that the EPA "may condition permission [to use an AMEL] on requirements related to the operation and maintenance of the alternative means."[92] Such requirements could easily include frequency of the deployment or operation of the AMEL.

V. AMEL – STATE EQUIVALENCY

A. The EPA Should Recognize the Approved State Programs as Wholly Equivalent to Subpart OOOOa LDAR Program and Fully Delegate the Implementation of the LDAR Monitoring Provisions to These Respective States.

Based on the EPA's state LDAR program equivalency guidance document provided with this rulemaking, the EPA explained that they analyzed the sensitivity thresholds and monitoring frequencies of approved technologies in a number of state programs, as well as other program requirements and, based on all of these variables combined, deemed these various state programs equivalent to Subpart OOOOa LDAR program.[93] However, the EPA is requiring operators to use the fugitive emission component definition from Subpart OOOOa, in addition to the reporting and monitoring plan. Many Independent Producers members are required to comply with state permit requirements and therefore, are currently implementing both the state and federal LDAR programs concurrently and the differing required recordkeeping and reporting requirements, as well as Subpart OOOOa's monitoring plan. This is a very burdensome duplicative administrative burden with no added benefit for the environment.

Under the well-established premise of cooperative federalism, the EPA should recognize these programs in full, including the states' recordkeeping and reporting requirements. The states have recordkeeping and reporting to ensure compliance with their programs and the EPA should give proper deference to states for compliance assurance for their state program. If the state program is not adequate in the EPA's opinion, then the EPA needs to address this issue with the states.

Complying with two different recordkeeping and reporting schemes on the same site(s) is an enormous administrative burden with no added environmental benefit. And requiring the federal reporting (which would require some Subpart OOOOa recordkeeping requirements to be

[92] 40 C.F.R. § 60.5398a(a).

[93] EPA's Memo. *Equivalency of State Fugitive Emissions Program for Well Sites and Compressor Stations to Proposed Standards at 40 CRF Part 60, Subpart OOOOa* (April 12, 2018).

met in order to comply with the federal reporting), and monitoring plan defeats the purpose and any benefit from the EPA approving these state programs in the first place.

Cooperative federalism is a central tenet of the CAA. Over the course of its fifty year history, the Act has evolved first from a set of general principles intended to guide States as they undertook regulation of air pollution sources, to an extensive number of more targeted standards often prescribed by the federal government in the first instance and then implemented by the states. The principle that the States and the federal government will work in tandem to protect the nation's air resources is embodied throughout the Act. Congress, in Section 101(a)(3) of the Act, declared air pollution control to be "the primary responsibility of States and local governments,"[94] with the federal government providing "financial assistance and leadership."[95]

For example, pursuant to Section 110 of the CAA, while the EPA develops the national ambient air quality standards,[96] states develop plans, called state implementation plans, to meet those standards. In that context, the U.S. Supreme Court has made clear that "[t]he Act gives the Agency no authority to question the wisdom of a State's choices of emission limitations if they are part of a plan which satisfies the standards."[97] Similarly, under the CAA's visibility provisions, states have broad leeway to develop plans to combat regional haze that the EPA cannot second-guess if the states have considered the statutory factors.[98]

Section 111, the provision at issue here, fits squarely within the cooperative federalism tradition, with section 111(c) expressly calling on states to develop "a procedure for implementing and enforcing standards of performance for new sources" and calling on the Administrator to delegate "any authority he has … to implement and enforce such standards."[99] The Supreme Court has affirmed that these cooperative principles are the heart of the CAA again and again.[100]

State LDAR programs are precisely the sort of regulation over which states have special expertise, and they are proper subjects of state control.

VI. <u>RECORDKEEPING AND REPORTING REQUIREMENTS</u>

The Independent Producers appreciate the changes the EPA has made to the Subpart OOOOa recordkeeping and reporting requirements, but we continue to believe further streamlining is necessary to reduce financial burden to operators, especially in those situations

---

[94] 42 U.S.C. § 7401(a)(3),

[95] i*d*. § 7401(a)(4).

[96] *see* 42 U.S.C. §§ 7408, 7409,

[97] *Train v. Natural Res. Def. Council, Inc.*, 421 U.S. 60, 79 (1975).

[98] *Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1, 8 (D.C. Cir. 2002).

[99] 42 U.S.C. § 7411(c)(1).

[100] *See, e.g.*, *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 470 (2001) ("It is to the States that the CAA assigns initial and primary responsibility for deciding what emissions reductions will be required from which sources."); *Union Elec. Co. v. EPA*, 427 U.S. 246, 269 (1976) ("Congress plainly left with the States, so long as the [NAAQS] were met, the power to determine which sources would be burdened by regulation and to what extent.").

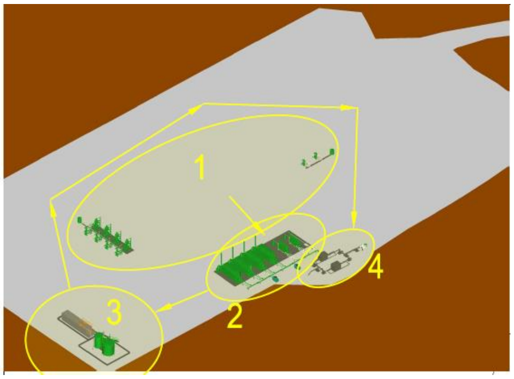
where the requirements do not enable the Agency to determine compliance. In these instances, we maintain that the increased financial burden caused by the excessive reporting and recordkeeping is unjustifiable. The Independent Producers believe further reductions and streamlining to the recordkeeping and reporting requirements are essential to the creation of an effective rule.

A. Well Completions

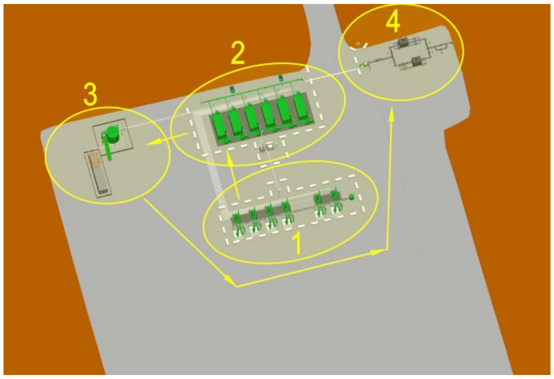
Section 60.5420a(b)(2) lists recordkeeping and reporting requirements for flowback routed through *permanent* separators. However, the presence of a permanent separator that was installed and operated from the onset would technically indicate that the flowback process never actually occurred making any recordkeeping and reporting requirements in these situations unnecessary and overly burdensome. The presence of a permanent separator indicates production has begun. The lack of a temporary separator and the absence of flaring and/or venting to accommodate emissions during flowback eliminates the necessity for any type of recordkeeping and reporting beyond simply acknowledging that the well went directly into production and no flowback occurred at that location.

B. Observation Path

It is most typical that the engineering footprint of equipment at a well site remains the same from site to site as the operating process does not change. This is most particular for well sites within the same basin. To that extent, it is rather redundant to require an observation path depicting the footpath of the surveyor when the inspection would necessarily follow to process flow of the equipment in order to capture all the potential leaks. For example, below are the actual Observation Paths of two independent well sites with the same process flow. As depicted, the footpath of the surveyor always follow the same sequence in terms of the process equipment.



Well Site A



Well Site B

In lieu of maintaining an Observation Path and Site Map for every well site, we would propose a description be included in the company's Monitoring Plan instructing the surveyor to follow the process flow. An example is as follows:

Perform an inspection of the following equipment in the sequence as follows: Well heads → Separators → Tanks → meter area. For each equipment, perform a 360 degrees inspection before proceeding to the next.

For Example - In Lieu of an observation path, we propose a description of how each "type" of equipment will be monitored via a description and location of each component being monitored.

C. Pneumatic Pumps

We recommend removing all recordkeeping and reporting requirements associated with the inspection of covers as referenced in §60.5416a(a). Covers are unique to storage vessels and have no reason to be listed in pump requirements.

D. Low Production Wells (Wildcat Wells, Delineation Wells, Low Pressure Wells, and Wells with GOR less than 300 scf/bbl)

The EPA continually fails to consider the massive financial, resource allocation, and administrative impacts resulting from the excessive amount of prescriptive requirements assigned to production facilities. What is more distressing is that these overly burdensome requirements are applied to all facilities independent of the level of production. The EPA seems to consider minor source production facilities on a level playing field with refineries and infinitely more complex operations that have thousands more components than even the largest applicable sources covered by this rule. The Independent Producers understand low production source (< 15 BOE) exemptions are being reconsidered [101] and urge The EPA to follow through with such an exemption, specifically concerning LDAR requirements and the associated recordkeeping and reporting. High volume recordkeeping, on par with large refineries, is not necessary and completely unjustified for these diminutive, financially sensitive sources.

E. Storage Tanks

The EPA is soliciting comments on the type of records necessary to ensure proper calculation of VOC emissions and maximum daily average (*i.e.*, daily measurements, liquid height measurements, start and end dates for each production period, number of days production was routed to a particular storage vessel, load slips when automated readings are unavailable, documentation of the operational configuration of the tank/tank battery, etc.). The EPA is also seeking comment on the perceived recordkeeping burden to operators.

It is unclear how the newly proposed maximum daily average calculations will help control, or reduce, emissions from storage vessel affected facilities, especially with respect to controlled tanks and/or tanks that are manifolded together. Consequently, the increased recordkeeping and reporting requirements that accompany this proposal are overly burdensome and without environmental benefit. Any increased recordkeeping and reporting requirements that result from disallowing emissions averaging over the entire tank batteries that share a common control device, or vent, are unnecessary. Furthermore, it is unclear if operators, especially small operators, even have the capability to monitor and record individual storage

---

[101] *See* Docket ID No. EPA-HQ-OAR-2010-0505-7730.

vessel throughputs as described in the EPA's proposed scenarios. Tank unloading operations are tracked by the total volume of liquids removed from the facility, as are the tank overheads in the shared manifold system and/or closed vent system ("CVS"), and not on an individual tank basis.

Thief hatch and PRV requirements associated with storage vessels that are not affected facilities, or part of a CVS, should be exempt from LDAR requirements (including recordkeeping and reporting), but due to their inclusion in the "fugitive emission components" definition [102] and the language in § 60.5397a(d)(1)(iv) [103] it seems unclear. Those emissions would have been accounted for in the PTE calculations and are not fugitive emissions.

F. Leak Detection and Repair

The Independent Producers overarching concern is that much more information is required to be documented than is necessary. Many items on the extensive list provide no environmental benefit, or assurance of compliance. Many operators consider Colorado Reg 7 to be overly burdensome, yet it is still more streamlined and efficient than what is currently required in this rule. The following list is inclusive of the recordkeeping and reporting requirements that should be stricken:

- How the leak was repaired
- Time of the survey
- Name/ID of person performing the survey
- Weather and atmospheric conditions
- Deviations from the monitoring plan, or observation path (if they do not create a situation where the survey results are been negatively affected by the modification)
- Type of instrument used to resurvey following a repair is unnecessary

When one asks "what useful information does this provide regulators in regards to compliance assurance?", it is difficult if not impossible to produce an answer that justifies their inclusion, especially considering the associated resource and economic burden. It is the Independent Producers' contention that Colorado Reg. 7 should be the template for fugitive recordkeeping and reporting and request EPA modify these requirements accordingly.

G. Digital Photograph Requirement

Mandating digital photographs, or video records be kept and maintained when using OGI technology does not serve a useful purpose, or in any way ensure compliance with the rule. The EPA has never made the determination that a digital photograph of the analyzer readout is necessary to ensure compliance when using a traditional Method 21 protocol to satisfy LDAR

[102] 40 C.F.R. §60.5430a ("Fugitive Emission Component" definition)

[103] For ***all other*** fugitive emission components ***not associated with a closed vent system or a controlled storage vessel*** under this section, a narrative description of how the fugitive emissions components will be monitored.

requirements, and it subsequently should not be required when using OGI. This is a perfect example of an instance where streamlining could be successfully utilized to remove unnecessary requirements that impart undue burden and financial stress without environmental benefit or additional compliance assurance beyond maintaining records and submitting certified reports that are already required.

H. Observation Path Requirement

The proposed observation path deviation reporting requirements should be eliminated. The EPA has failed to provide adequate proof that this is necessary for compliance assurance, or address industry concerns related to the overly burdensome nature of the tracking, maintenance, and modification of the monitoring plan and/or observation path documents that would be needed to avoid deviation reporting. The CAA authorizes the EPA to promulgate performance standards, but it does not authorize the EPA to force owner/operators to use a single method of complying with those standards. In fact, the CAA mandates that the EPA allow owner/operators the flexibility to determine the most effective compliance method for specific requirements. Adherence to a prescriptive observation path, where even a slight departure creates a potential compliance issue through "deviation" reporting requirements, is unnecessary and in no way correlates to a more effective performance of the survey, or in any way contributes to a reduction of emissions. Facilities are frequently modified and changed through equipment and component additions/removals which creates a perpetual evolution regarding the most effective camera position for successful OGI surveys. Even in situations where the facility equipment has not changed, weather conditions and other environmental factors create scenarios where the survey approach needs to be adjusted in order to achieve the desired result. These on-the-fly adjustments to the monitoring plan and/or observation path should not be considered a reportable deviation. Furthermore, they are absolutely critical to the successful outcome of the survey and applying any sort of negative association by reporting them as "deviations" is counterproductive to the overall intent of the rule. The Independent Producers understand that the EPA has stated that deviations from the monitoring plan are not necessarily deviations from the rule requirements,[104] but we have a difficult time reconciling that when considering the definition of deviation[105] and the very real possibility that regulators will view these reported "deviations" as a failure to meet the requirements of the regulation as the definition suggests. Deviation reporting would also make any Title V facilities subject to OOOOa requirements vulnerable to additional reporting, and possibly enforcement action due to the deviation reporting requirements for major sources.

The EPA has failed to provide a satisfactory explanation for the inclusion of the very tedious and costly recordkeeping and reporting requirements regarding monitoring plans and observation paths, especially considering there are much simpler and more reasonable methods for achieving compliance assurance. The Independent Producers urge the EPA to remove the recordkeeping and reporting requirements regarding deviations and replace them with more flexible performance based standards. These could include requirements for images to be obtained with an unobstructed view (when possible), a requirement that all affected facilities and

[104] 83 Fed. Reg. at 52078

[105] 40 C.F.R. § 60.5430a ("Deviation" definition)

components must be surveyed, a requirement for the operator to position the camera in such a manner that the most accurate image is captured, etc. In the event EPA chooses to maintain the deviation reporting requirements for monitoring plans and observation paths it is imperative that the definition of deviation be modified such that minor changes that are necessary to effectively and satisfactorily to complete the survey are not included.

1. Compliance and Emissions Data Reporting Interface ("CEDRI")

The Independent Producers understand that the CEDRI system is being reconsidered, but we still maintain that after it has been activated that an extended transition period must be utilized to eliminate delays and compliance issues related to system bugs and other integration problems. In addition, it has come to our attention that the few operators that have attempted to use the electronic reporting system have discovered that the process of obtaining facility ID's by first loading all facilities into CEDRI is extremely burdensome with respect to time and resources. This extra step is necessary before data can even begin to be entered into the system. The process of obtaining facility ID's must be simplified before the CEDRI system can be considered an acceptable method of data reporting.

VII. DEFINITION OF MODIFICATION

A. The EPA's Assumptions Associated with Refracturing a Well Does Not Justify Abandoning a Demonstrated Emissions Increase.

The definition of "Modification of a Well Site" proposed by the EPA in the NSPS for the Oil and Natural Gas Sector, 40 CFR 60.5365 a(i)(3), is inconsistent with the definition of "modification" under Section 111 of the CAA both in concept and fact. In the context of the EPA's immediate need to consider staying the fugitive emissions requirements, the impact of the Subpart OOOOa NSPS on modifications is significant. The CAA defines "modification" in the context of Section 111 as:

> … any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.[106]

This is not the criteria that the EPA used in defining "modification" in Subpart OOOOa. In Subpart OOOOa, the EPA states:

> A "modification" to a well site occurs when:
>
> (i) A new well is drilled at an existing well site;
>
> (ii) A well at an existing well site is hydraulically fractured; or

[106] 42 U.S.C.A. § 7411(a)(4).

(iii) A well at an existing well site is hydraulically refractured.[107]

The EPA justifies its use of this definition in the Federal Register Notice on Subpart OOOOa by stating:

> The EPA believes the addition of a new well or the hydraulically fracturing or refracturing of an existing well will increase emissions from the well site for the following reasons. These events are followed by production from these wells which generate additional emissions at the well sites. Some of these additional emissions will pass through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components). Further, it is not uncommon that an increase in production would require additional equipment and, therefore, additional fugitive emission components at the well sites. We also believe that defining "modification" to include these two events, rather than requiring complex case-by-case analysis to determine whether there is emission increase in each event, will ease implementation burden of owners and operators. For the reasons stated above, EPA is finalizing the definition of "modification" of a well site, as proposed.[108]

This rationale is generally incorrect as a matter of concept because emissions do not arise from the fracturing of a well, but from production and the equipment to manage these emissions which are in place at the time of the fracturing. In addition, it is factually incorrect to automatically associate an increase in fugitive emissions and, as a result, a "modification" with each instance when a well is refractured. Production from any oil and natural gas well will always decline over time. The graph on page 9 of these Comments shows a typical decline curve for hydraulically fractured wells. Refracturing a well is a normal operational practice to recover some portion of declining production from existing wells. A refractured well will seldom, if ever, bring its production back to its initial volume or operating pressure. If an operator is committed to the expense associated with refracturing a well, part of standard operating practices are to evaluate the equipment on site to ensure that as much gas is recovered as possible. Again – what the EPA views as a pollutant, the industry views as its product. The equipment designed and installed at a particular well is designed to capture the maximum amount of methane or "emissions" that well is anticipated to produce when initially fractured. That same equipment is most likely "oversized" for a refracturing of the well.

The occurrence of a modification under the overarching definition contained in Section 111 requires a calculated increase in the baseline level of actual emissions.[109] Although the CAA defines a "modification" as any physical or operational change causing increased emissions, it does not specify how to calculate "increases" in emissions.[110] If the legislative intent of a statutory provision is ambiguous, then a court is entitled to consider "whether the agency's

---

[107] 81 Fed. Reg. 35900 (June 3, 2016).

[108] 81 Fed Reg. 35881 (June 3, 2016).

[109] *New York v. U.S. Environmental Protection Agency*, 413 F.3d. 3, 19 (D.C. Cir., 2005).

[110] 42 U.S.C.A. §7411(a)(4).

[interpretation]is based on a permissible construction of the statute.[111] In the event the Agency's application meets that standard, a court will give that interpretation "controlling weight unless [it is] arbitrary, capricious or manifestly contrary to the statute.[112] The NSPS does not provide any methodology to support its definition of "modification", it simply assumes that any hydraulic refracture results in increased emissions. Refracturing a low production well is simply does not restore an underperforming well to levels that exceed or even come close to its original production level.

B. The EPA Acknowledged its Logical Inconsistency but has Failed to Justify Such Inconsistency.

In the Reconsideration Rulemaking, the EPA quoted comments previously made by the Independent Producers, not once but twice:

> EPA's rationale, that fugitive emissions are a function of the number and types of equipment, and not operating parameters such as pressure and volume, is inconsistent with EPA's justification for what constitutes a 'modification' for an existing well site. EPA assumes that fracturing or refracturing an existing well will increase emissions because of the additional production, i.e., the additional pressure and volume. EPA cannot ignore the laws of physics to the detriment of low production wells in one instance and then 'honor' them in another contexts to eliminate an 'emissions increase' requirement in the traditional definition of 'modification.;[113]

The EPA continues to argue that additional equipment will be installed when a well is refractured despite industry's statements to the contrary. In some instances additional equipment may be added but for the most part, equipment is not added. The equipment is designed to the capture the pressures and volumes expected from the initial fracture. The EPA's rational also assumes leaks at the existing equipment. The EPA also discusses other hypothetical instances where a refracture *could* result in an emissions increase.[114] The EPA's rational relies on the words "could", "may" and "possibly." This should not be the basis for regulating thousands of existing sources. If the EPA is intent on assuming emissions increases with refracturing a well, which seems heavily reliant on the assumption of leaking components, The EPA should allow operators to conduct a pre-refracture LDAR survey option, which, if demonstrates no leaks, would allow for refracturing that does not trigger a modification.

The EPA also attempts to explain away the inconstancy by citing "support for the petitioners' assertion that equipment counts can vary based on the amount of production at a well site."[115] The Independent Producers do not dispute that the number of equipment counts can and does vary based on the amount of production at a well site. That fact does not justify EPA

---

[111] *Chevron U.S.A., Inc. v. Natural Res. Def. Council*, 467 U.S. 837, 843 (1984).

[112] *Chevron* at 844.

[113] 83 Fed. Reg. 52,067; 83 Fed. Reg. 52,073 (2018).

[114] 83 Fed. Reg. 52,073 (2018).

[115] 83 Fed. Reg. 52,067 (2018).

ignoring or substantially discounting the impact of decreased production/pressure/volume at low production wells and the impact on emissions. While the Independent Producers appreciate the EPA's efforts to create a Model Low Production Well, as discussed earlier, the assumed equipment counts are high and overestimate emissions from low production wells.

VIII. CONCLUSIONS

The Reconsideration Rulemaking creates opportunities to address issues that were not fully understood or considered in the rush to complete Subpart OOOOa under the political pressures of the previous Administration. The Independent Producers support this essential action. In particular, the Independent Producers support the following positive changes:

> Changing the large production well fugitive emissions program to an annual cycle. The EPA's initial actions in Subpart OOOOa were based on inaccurate assumptions. As the API has identified, both the initial failure rate and the time for subsequent actions were incorrect and drove the EPA to overvalue a semi-annual cycle. The revisions to an annual cycle is an appropriate step.
>
> Addressing the requirements to use a Professional Engineer to certify certain actions and the revisions to the provisions on pneumatic pumps are important steps forward but both need additional clarification and modifications.

However, as stated above, the Independent Producers believe that additional changes are essential to fully address the regulatory framework in Subparts OOOO and OOOOa as they affect America's oil and natural gas productions. These include:

> The resurrection of a distinction for low production wells is a key and essential part of the new proposal. However, as the Independent Producers discuss above, the proposal falls short of being a workable structure. No specific requirements for low production wells should be required unless and until the EPA obtains specific information on low production well emissions and determines regulations are necessary and that cost-effective regulations can be created.
>
> The EPA's proposal on storage vessels needs to be significantly revised or eliminated. The Agency's proposal to prohibit averaging of throughput across tank batteries inappropriately ignores the relevant process unit and is inconsistent with recent consent decrees related to the design and operation of vapor control systems on storage tanks/vessels. The EPA's concern about the amount of storage vessels subject to Subpart OOOOa is overstated and unfounded. Its proposal to calculate individual tank emissions based upon throughput to each individual tank is technically flawed and overly burdensome. The EPA's proposed revisions to what constitutes "legally and practically enforceable limits" is unnecessary and arbitrarily interferes with the Clean Air Act's cooperative federalism where the states are to take lead on implementation.
>
> The Independent Producers support the AMEL options in the proposal to use modeling to test technologies in a controlled test environment, and to allow manufactures/vendors to apply for approvals. However, the EPA should allow for basin-wide approvals of emerging technology for use in complying with the LDAR requirements in the rule.

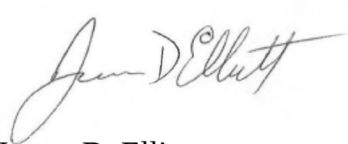
The EPA should recognize the approved state LDAR programs as wholly ambivalent to Subpart 0000's LDAR program and fully delegate the implementation of the LDAR monitoring provisions to these respective states. Alternatively, the EPA could require the fugitive emissions component definition from Subpart 0000a to be used when following an alternative approved state program, but the EPA should not require a duplicative administrative burden; to do so would be an undue burden with no corresponding environmental benefit.

The Independent Producers believe that further changes to limit excessive recordkeeping and reporting need to be made – changes to prevent unnecessary burdens that have no environmental benefit – and the definition of "modification" should be refined to be consistent with the intent of the CAA.

The Independent Producers submit these Comments collectively. The Independent Producers also endorse those Comments that are submitted separately by member organizations. Additionally, the Independent Producers support the Comments and proposals submitted by the API and commend its information supporting an annual fugitive emissions program for large production wells to the EPA.

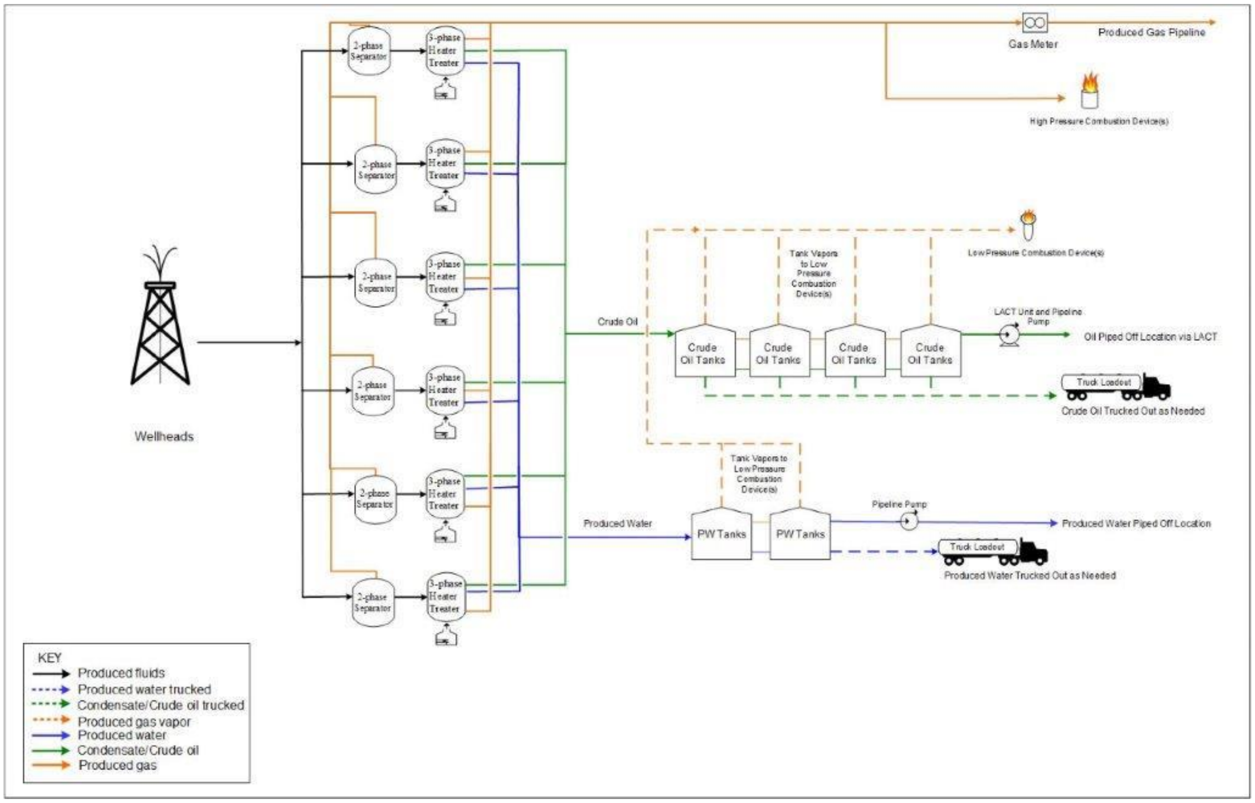
If there are questions regarding these Comments, please contact me, counsel for the Independent Producers.

Respectfully submitted,



James D. Elliott
Counsel for Independent Producers

APPENDIX A


Gas Meter
Produced Gas Pipeline
High Pressure Combustion Device(s)
2-phase Separator
3-phase Heater Treater
Wellheads
Low Pressure Combustion Device(s)
Tank Vapors to Low Pressure Combustion Device(s)
Crude Oil
Crude Oil Tanks
LACT Unit and Pipeline Pump
Oil Piped Off Location via LACT
Truck Loadout
Crude Oil Trucked Out as Needed
Tank Vapors to Low Pressure Combustion Device(s)
Produced Water
PW Tanks
Pipeline Pump
Produced Water Piped Off Location
Truck Loadout
Produced Water Trucked Out as Needed
KEY
Produced fluids
Produced water trucked
Condensate/Crude oil trucked
Produced gas vapor
Produced water
Condensate/Crude oil
Produced gas

APPENDIX C

Response/Supplemental Comments

The Honorable Andrew Wheeler, Administrator   ***VIA E-MAIL AND E-FILING***
US Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.   June 17, 2019
Washington, DC 20460

Re: Environmental Protection Agency's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration at 83 Federal Register 52056 (October 15, 2018) – Supplemental Comments

Docket ID No. EPA-HQ-OAR-2017-0483

Dear Administrator Wheeler:

The following Supplemental Comments are submitted on the above-referenced proposed Reconsideration Rulemaking ("Reconsideration Rulemaking") on behalf of the following national and state trade associations: the Independent Petroleum Association of America ("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"), Oklahoma Independent Petroleum Association ("OIPA"), 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 Independent Producers have participated individually or through the Independent Producers in most, if not all, of the rulemakings and associated litigation since the Environmental Protection Agency ("EPA" or "Agency") proposed to revise the New Source Performance Standards ("NSPS") for the Oil and Natural Gas Sector in August 2011. 76 Fed. Reg. 52,738 (Aug. 23, 2011).[1] While many of the Independent Producers represent companies that engage in large volume hydraulic fracturing with horizontal legs, often referred to as unconventional drilling, a significant portion of their membership is also comprised of smaller, family run operations that engage in some form of hydraulic fracturing, involving vertical wells without horizontal legs, referred to as conventional oil or natural gas wells. Many

[1] As EPA has opened a new docket for the Reconsideration Rulemaking, the Independent Producers incorporate by reference their Comments on the previous rulemakings associated with 40 C.F.R. Part 60, Subpart OOOO and Subpart OOOOa, including but not limited to the following documents: EPA-HQ-OAR-2010-0505-4216, EPA-HQ-OAR-2010-0505-4626, EPA-HQ-OAR-2010-0505-4752, EPA-HQ-OAR-2010-0505-4767, EPA-HQ-OAR-2010-0505-7001, EPA-HQ-OAR-2010-0505-7685, and EPA-HQ-OAR-2010-0505-12337

of the individual members constitute small businesses under the Small Business Regulatory Enforcement Fairness Act of 1996.

These supplemental comments are filed by the Independent Producers in response to initial comments and supplemental comments filed by others, including some that directly address the Independent Producers initial comments (filed December 17, 2018).

Framing the Issues

The Independent Producers comments addressed several key issues where the proposed Reconsideration Rulemaking adversely affect American oil and natural gas production. These include the following that were directly addressed in comments by others:

1. Alternative Means of Emission Limitation (AMEL) for state equivalency to the required leak detection and repair (LDAR) provisions for fugitive emissions; and,
2. The treatment of low production wells

To put these supplemental comments in context, following are synopses of the initial Independent Producers comments on these issues.

AMEL for emerging technology and state equivalency to the required leak detection and repair (LDAR) provisions for fugitive emissions

The Independent Producers support the options in the Proposed Revisions to use modeling, to test technologies in a controlled test environment, and to allow manufactures/vendors to apply for approvals. EPA should allow for basin-wide approvals of emerging technology for use in complying with the LDAR requirements in the rule. EPA can establish clear and consistent parameters under which a technology will be able to detect methane emissions and site specific variables can be addressed in conditions required for the use of the technology. Basin-wide data is necessary to determine equivalency and receive approval per CAA 111(h); basin-wide surveys that can identify potential fat-tail emission sources faster and per the EPA, higher mass emission reductions from large leaks, found earlier, are offset by some degree by smaller leaks which go undetected. Common sense dictates basin-level approval; the 111(h) notice and comment process required to achieve approval is very onerous and not feasible to do for every single well site. CAA Sec. 111(h)(3) does not constrain basin-wide approvals.

Per cooperative federalism, EPA should recognize the approved state programs as wholly equivalent to 40 C.F.R. Part 60, Subpart OOOO's ("Subpart OOOO") LDAR program and fully delegate the implementation of the LDAR monitoring provisions to these respective states. Alternatively, EPA could require the fugitive emissions component definition from Subpart OOOOa to be used when following an alternative approved state program but EPA should not require a duplicative administrative burden; to do so would be an undue burden with no corresponding environmental benefit.

The treatment of low production wells

Subpart OOOOa in the context of its application to oil and natural gas production emissions expands on a regulatory network that includes Subpart OOOO. Subpart OOOO applies to the significantly more substantial emissions sources. However, in their entirety, these oil and natural gas production sources currently account for approximately 1.2 percent of the US Greenhouse Gas Inventory (GHGI).

There are approximately one million oil and natural gas wells in the United States. Within this category of sources are low production oil and natural gas wells (wells producing 15 b/d or less or 90 mcfd or less).

There are approximately 770,000 low production oil and natural gas wells in the United States. These wells account for about 10 percent of US oil production and 12.5 percent of US natural gas production. If these wells emit methane comparable to their production volumes, they would account for an amount less than 0.15 percent of the total GHGI.

While Subpart OOOOa addresses new and modified sources, because it applies to a non-criteria, non-hazardous chemical – methane – it will trigger a nationwide existing source regulatory requirement for oil and natural gas production facilities – Section 111(d). Section 111(d) was squeezed into the Clean Air Act to address what can only be understood as a small number of pollutants that would not fall into the larger categories – and correspondingly – to a small number of sources. Section 111(d) was never envisioned as a regulatory framework for a source category with a million facilities.

EPA's creation of an expensive, burdensome and ineffective Optical Gas Imaging (OGI) LDAR fugitive emissions program for low production wells in Subpart OOOOa threatens the economic viability of existing low production wells without a sound basis or reasonable expectations of emissions reductions. While emissions information has been gathered from oil and natural gas production operations, none of these efforts was designed to address low production wells. Rather, low production well data has been culled from the larger data pool. The vast majority of data collected does not distinguish fugitive emissions from permitted emissions. Similarly, when EPA has turned to alternative approaches of using component counts and emissions factors, it has relied on data from an extremely small sample of low production wells and from emissions factors based on a 25-year-old study. Neither that study nor the more recent emissions studies were designed for the purpose of crafting regulations. The Independent Producers believe this information is insufficient to impose requirements that disproportionately affect low production wells.

The Department of Energy (DOE) has initiated a study of low production well emissions that should be finished before low production well regulations are required and could be used to develop a sound low production well regulatory framework if one is necessary.

These supplemental comments will address comments filed by the Joint Environmental Coalition (JEC) on the initial proposed revisions to Subpart OOOOa as well as their supplemental comments submitted by February 21, 2019. The JEC members are advocates for the termination of American fossil energy production. The JEC comments must be viewed in the context that their underlying objective is to produce EPA actions that prevent new American oil and natural gas production and terminate existing American oil and natural gas production. These supplemental comments address comments by the JEC seeking to stop American production that are inaccurate or address issues of particular concern to the Independent Producers.

The organization of these comments will be:

1. A review of the JEC basis for its positions
2. Responses to the JEC Supplemental Filing – February 21, 2019 – Criticisms of Industry Comments with a principal focus on the low production well issues raised

3. Responses to the JEC initial Comments with a principal focus on low production well issues; and,
4. A response to JEC issues related to AMEL for state equivalency.

Joint Environmental Coalition Basis for Its Positions

At the center of the comments submitted by the JEC are a series of studies and reports that present its perspectives on methane emissions related to the production of American natural gas and oil. Each of these items present highly inaccurate and questionable assessments and present them with strident evangelical certainty that vastly overstates their accuracy and value. To place the JEC arguments and criticisms in context, it is useful to review documents cited in their comments.

1. *Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF Study)*

This report funded by EDF created an array of cost effectiveness calculations in $/mcf based on a series of critical assumptions. Since its completion, EDF and other members of the JEC have touted it as demonstrating that methane emissions can be reduced with technologies that only cost cents per day. While aggregating all of the cost effective technologies with the cost ineffective technologies might produce such a result, individual technology options do not. Equally significant are the EDF assumptions of the value of natural gas in calculating the benefits of regulations and the efficiency of the requirements. These are particularly important in the context of the fugitive emissions proposals.

EDF concludes that a quarterly fugitive emissions program for natural gas wells would recover 264 mcf/y using a 60 percent recovery rate on emissions of 440 mcf/y and have a cost burden of $7.60/mcf without recovery benefits and $2.52/mcf with recovery.

Putting this evaluation in some context changes the perspective. First, looking at the emissions and recovery quantities on a daily basis shows them to be 0.72 mcfd and 1.2 mcfd, respectively. These are small volumes for even the average well. EDF does not indicate the average production rate for the wells it assumes for the average emissions, but the average US natural gas well produces about 127 mcfd. Therefore, the approximate emissions rate would be about 1.0 percent. Nor does EDF appear to distinguish sources of emissions in its fugitive discussion. For example, it does not discuss the share of emissions coming from equipment and those coming from storage tanks that have permitted releases. Since an LDAR program would not apply to these allowable emissions, the efficiency/cost estimates must be questioned.

A second key point of the analysis relates to the value of natural gas where EDF assumes a price of $4.00/mcf. Producers have not received such a price for a long time and do not foresee such a price for many years. As the Independent Producers submitted in its original comments, the recent price for natural gas has been nearer $2.22/mcf of which the producer receives approximately $1.67/mcf. If this price replaces the EDF assumptions, the value of the recovered natural gas would drop from $1360 to $440 annually. Correspondingly, the cost effectiveness would change in the net case from $2.52/mcf to $5.48/mcf.

A third point relates to the scope of fugitive leaks of the Leak Detection and Repair (LDAR) program. A study done by Carbon Limits (described below) concluded that fugitive leak emissions at well sites accounted for 17 percent of the total site emissions. Using this assessment of the 440 mcf/y of site emissions, only 75 mcf/y would be addressed by the LDAR program. And using the generous assumption of a 60 percent recovery, 45 mcf/y (0.12 mcfd) would be recovered. This would result in $75 in recovered value. The cost effectiveness would then become $44.58/mcf in the gross case and $42.91/mcf in the net case

More critically, the issue of larger significance here is the application of an LDAR program to low production wells. These wells average about 24 mcfd rather than 127 mcfd. Moreover, in some significant natural gas producing states the average low production natural gas well is much less; in Pennsylvania, for example, it is 6.1 mcfd. Using the same ratio of emissions to production for the average national well would yield low production emissions rates of 0.24 mcfd nationally and 0.06 mcfd for Pennsylvania. On this basis the potential recovery would be 9 mcf/y for the national average low production well and 2.2 mcf/y for the Pennsylvania well. The gross and net cost effectiveness values would be $222.89/mcf and $221.22/mcf for the national wells and $911.81/mcf and $910.15/mcf for the Pennsylvania wells, respectively. Setting aside that most of the likely emissions would be from permitted storage tank vents, these assessments argue that the Optical Gas Imaging OGI LDAR approach is not cost effective.

2. *Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras (Carbon Limits)*

This report was prepared for the Clean Air Task Force by Carbon Limits. It is designed to assess LDAR programs using infrared cameras for various components of the natural gas value chain. Environmentalists like to reference it because of its general conclusions that these LDAR programs can be cost effective. But, a closer look reveals a number of key points that demonstrate a very different result particularly in the context of low production wells.

First, like other analyses this report is based on recovering methane at a natural gas price of $4.00/mcf. While it does develop an effect case if natural gas were priced at $3.00/mcf, it does not approach an analysis at the $1.67/mcf prices that have characterized the recent prices that producers receive.

Second, as mentioned above, it concludes that natural gas well leaks that would be the subject of an LDAR program represent only 17 percent of the methane emissions from well sites.

Third, the report develops Net Present Value (NPV) determinations for each industry segment that it evaluates — well sites and well batteries, gas processing plants and compressor stations in gas transmission, and gas gathering systems. For well sites and well batteries, the Carbon Limits study concludes that infrared camera based LDAR programs are not cost effective at 85 percent of these sites — a percentage that exceeds the share of natural gas production facilities that are low production wells. Moreover, since this assessment is based on $4.00/mcf natural gas, it would thereby mean that such an LDAR program would be not be cost effective for an even greater percentage.

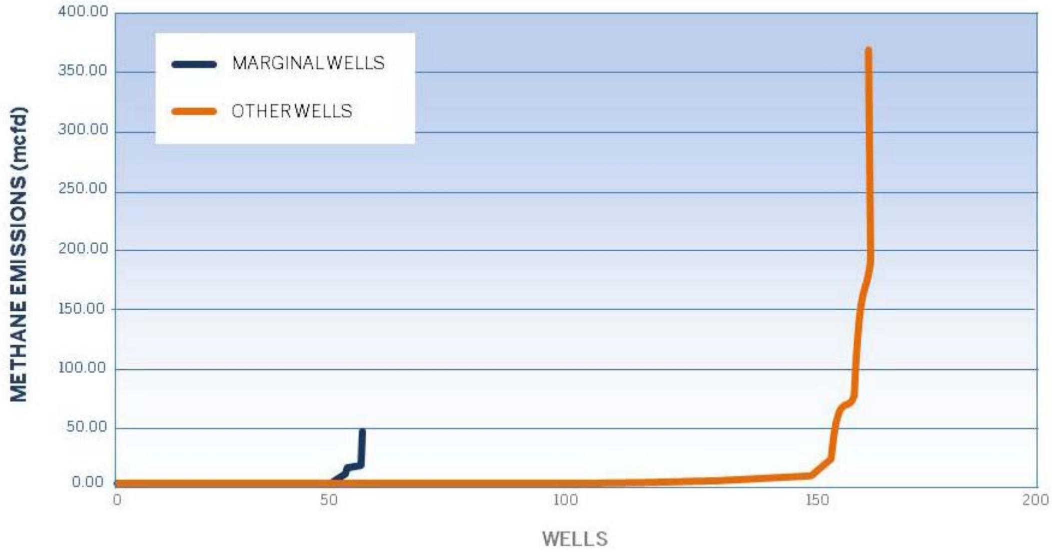
3. *Waste Not: Common Sense Ways to Reduce Methane Pollution from the Oil and Natural Gas Industry (Waste Not)*

This report was prepared by the Clean Air Task Force, the Natural Resources Defense Council and the Sierra Club. It essentially presents information from other sources arguing for a methane-based expansion of Subpart OOOO in order to expand regulation to existing sources. Its information is largely restatements of the information from the ICF and Carbon Limits reports described previously and therefore suffers from the same limitations, including the use of a natural gas value of $4/mcf. Moreover, since it predates Subpart OOOOa, much of its emissions reduction calculations apply to the broad array of possible regulations and are not limited to those addressed in the Subpart OOOOa reconsideration. The only intriguing element of its recommendations in the realization that a fugitive emissions program needs to differentiate its requirements based on the production volumes of the facility.

4. *Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites (Super-Emitters)*

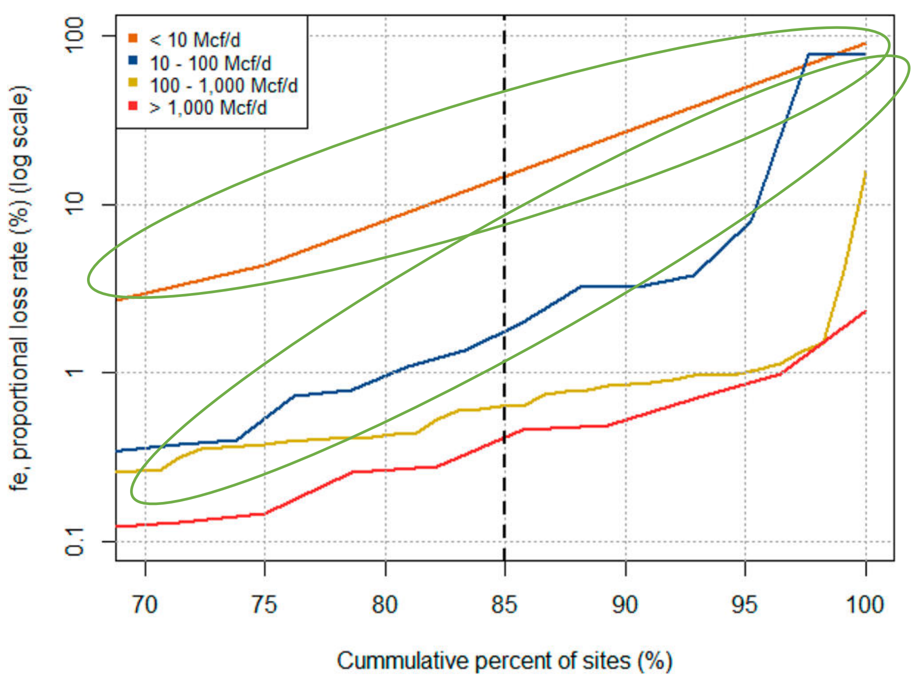
This study was commissioned by the EDF and clearly demonstrates the outcome-based purpose of the effort. It represents an effort to carefully cull data from other efforts and recast it as a new analysis to create the impression that low production wells are "super-emitters". It manipulates data to twist reality for the purpose of convincing EPA and others to regulate low production wells. The Independent Producers have addressed the abusive structure of this study in earlier comments. Those statements are restated herein:

> **Manipulating Data to Create the Illusion That Low Producing Wells Are "Super-Emitters"**
>
> This document addresses data manipulation issues in the environmentalist study submitted to the rulemaking proposal for Subpart OOOOa to distort the role of low producing wells regarding methane emissions. This study was then characterized as the basis for removing the low producing well exclusion for the Subpart OOOOa fugitive emissions program initially proposed by the Environmental Protection Agency (EPA).
>
> **Background**
>
> Initially, it is important to understand that this study used data from a number of different studies to create its arguments. All of the underlying studies generated their data by driving vehicles with samplers downwind of production sites, hunting for methane plumes. None of them used samples taken on the production site. This creates two issues. First, it measures everything emitted at the site – fugitive emissions and permitted vents. Second, the data are collected over minutes – maybe over an hour – but not over a day. The data in the study are presented as if they were daily emissions but the studies merely scale up hourly estimates. Consequently, an emission that might occur for several hours, but not the full day, would be overstated.
>
> Before turning further to describe the submitted study, it is useful to look at the same data using a direct graph of emissions. In this graph, marginal wells are those with production volumes of 90 mcfd or less.



This graph is consistent with information from other studies showing that a small portion of wells have an emission profile for some reason with high emissions and most wells have really low emissions. Importantly, it also clearly shows that marginal wells – low producing wells in the context of the regulation – have far smaller emissions. But, since this graph is using the same data as the study, it could also be overstating emissions because of scaling short term emissions to a daily amount.

With this background, turning to the presentation of the same material in the study demonstrates how it was manipulated. Below is the graphic used to present the data. It would suggest that the worst emitting operations – the "super-emitters" –



are the smallest wells (the orange line and the blue line, circled in green). Having directly plotted this data, the obvious issue is how such a result can occur.

It is a busy and confusing graph – it's intended to be. The study uses data analysis tricks to create the appearance that marginal wells are "super-emitters".

First, it shows emissions as a percentage of production rather than actual emissions. Thus, one mcf emitted out of ten mcf produced is 10 percent, but 50 mcf emitted out of 1000 mcf produced is 5 percent. As a result, it skews the perception of the data to imply that low producing wells are large emitters when they are not.

Second, its production volumes are really sales volumes, not the amount extracted from the wellhead. Consequently, a "proportional loss rate" of 50 percent would be the calculated loss divided by the volume sold. If the percentage of loss were calculated based on extracted volumes, the 50 percent "proportional loss rate" would drop to 33 percent because the loss would be added to the sales volume to obtain the extracted volume.

Third, it only shows data from the 70th percentile of information. This excludes all of the virtually zero emissions that dominate the data.

Fourth, it uses a logarithmic scale to present the data. One of the reasons to use logarithmic scales is to flatten curves to make them look more like straight lines.

5. *Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites (Lyon 2016)*

This report was completed for the Environmental Defense Fund and utilizes aerial data collection techniques to develop information. The data for the report were taken from June through October 2014. Consequently, of the 8220 well pads that were sampled, only 1574 would have been subject to the requirements of Subpart OOOO which became effective for new facilities after August 2011.

The study provides some useful insights. For example, it states:

> Tank hatches and tank vents were the most common source type of detected emissions, comprising 92% of observed sources. The remaining 8% of detected emission sources were dehydrators, separators, trucks unloading oil from tanks, and unlit or malfunctioning flares.

Of these, 184 would have been under the Subpart OOOO requirements. The remainder would have been allowed to have vented emissions without federal requirements for vapor recovery. In addition to vented emissions, tanks can have emissions from open hatches or corrupted seals.

The report also observes that its data may not reflect annual emissions information stating:

> Since our observations were limited to summer/fall and daylight hours, we were not able to assess how annual average prevalence may be affected by seasonal or diurnal trends such as higher tank breathing losses during warmer conditions.

This is a plausible issue since temperature can affect breathing losses.

Additionally, the validity of aerial surveys is an issue that has been questioned because – like other forms of data collection that is both based on measurements of sites from offsite and on measurements that are taken for a limited period of time and then extrapolated to daily or annual emissions – the lack of information on site operational conditions can result in inaccurate assessments. This issue has been addressed in a study published in 2018, *Temporal variability largely explains top-down/bottom-up difference in methane emission estimates from a natural gas production region*, which makes the following observation:

> This study spatially and temporally aligns top-down and bottom-up methane emission estimates for a natural gas production basin, using multiscale emission measurements and detailed activity data reporting. We show that episodic venting from manual liquid unloadings, which occur at a small fraction of natural gas well pads, drives a factor-of-two temporal variation in the basin-scale emission rate of a US dry shale gas play. The midafternoon peak emission rate aligns with the sampling time of all regional aircraft emission studies, which target well-mixed boundary layer conditions present in the afternoon. A mechanistic understanding of emission estimates derived from various methods is critical for unbiased emission verification and effective greenhouse gas emission mitigation. Our results demonstrate that direct comparison of emission estimates from methods covering widely different timescales can be misleading.

Like other reports, this one was not structured to specifically address low production wells but it includes information that presents some useful insights regarding the low production wells it sampled. Of the 8220 well pads sampled, 4195 were low production wells (15 BOE/day or less), averaging 4.1 BOE/day. Of these 4195 low production wells, 57 had measurable emissions (1.3 percent). Of these, 37 had tank vent emissions, 8 had tank hatch emissions and 2 had both tank vent and hatch emissions. The remaining 10 (0.2 percent) had emissions from dehydrators, separators, trucks unloading oil from tanks, and unlit or malfunctioning flares. These emissions are not clarified regarding whether the emissions would be considered as fugitive or whether they are from allowable vents or normal operations (e.g., truck unloading). However, it does clearly call into question the benefits of an OGI based fugitive emission program to address the small percentage of low production wells that would be dealing with non-tank emissions.

6. *Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin (Omara Marcellus 2016)*

This report includes information on both unconventional natural gas wells and conventional natural gas wells. For both types of wells remote sensing of emissions was undertaken and the facilities were examined using OGI, although most of the site examinations occurred without the participation of the facility operator. Among the report's conclusion is the following:

> Based on our results, the estimated 2014 CH4 leakage from all routinely producing NG well pad sites, as a fraction of statewide CH4 production, was 1.0% in Pennsylvania … and 3.0% in West Virginia …. The combined regional CH4 emissions (1150 Gg, Table 1) represented approximately 1.4% … of total Marcellus CH4 production (i.e., production from all routinely producing UNG and C_vNG sites in PA and WV combined) in 2014.

However, as Energy In Depth reports:

> Importantly, Omara et al. is actually part of a larger federally-funded study (Presto et al.) that began in the Marcellus and eventually was expanded to include several basins across the country. That more recent and comprehensive study found that methane emission estimates for Pennsylvania and West Virginia were **actually 40 percent lower than those reported in Omara et al. — the study EDF bases its estimates off of** – due to "improved statistical power in the current study and methodological differences in the treatment of high emitting sites."
>
> Specifically, the **more comprehensive 2017 study** found,
>
> > "From the 511,000 O&G production sites, we estimated total U.S. onshore CH4 emissions of 700,000 kg/h (or 6.1 million metric tons) in 2015. **These CH4 emissions were equivalent to 1.43% of total CH4 production in 2015**, or 1.6 kg/h/site." (emphasis added)
>
> …
>
> The more comprehensive 2017 study also determined that 2015 methane emissions leakage rates in both the southwestern and northeastern parts of the state were **less than one percent of production**. This is significant for a variety of reasons, the biggest being that in order for natural gas to maintain its climate benefits methane leakage rates have to **fall below 3.2 percent** – and they are well below that rate in Pennsylvania. Importantly, the leakage rate estimate from the more recent and comprehensive 2017 study includes conventional sites (i.e. generally older equipment) and wells from the southwestern portion of the state where the gas is "wet," meaning there are more natural gas liquids (NGLs) and thus more equipment on site (i.e. more opportunity for leaks). Still, the study found leakage rates **well below one percent of production**.

The report includes information from 19 conventional natural gas wells at 18 well pads, all of which are low production wells. The report suggests that emissions from these wells are proportionally higher than those from unconventional wells. Looking at the data more closely reveals some key facts.

First, it is important to recognize that this report suffers from the same limitations as most others. Its emissions information is taken remotely for limited times and cannot be converted accurately to either daily or annual emissions. Consequently, using the emissions determinations in the report should not be considered as accepting them as accurate. As the information above indicates, subsequent reports show far lower emissions rates.

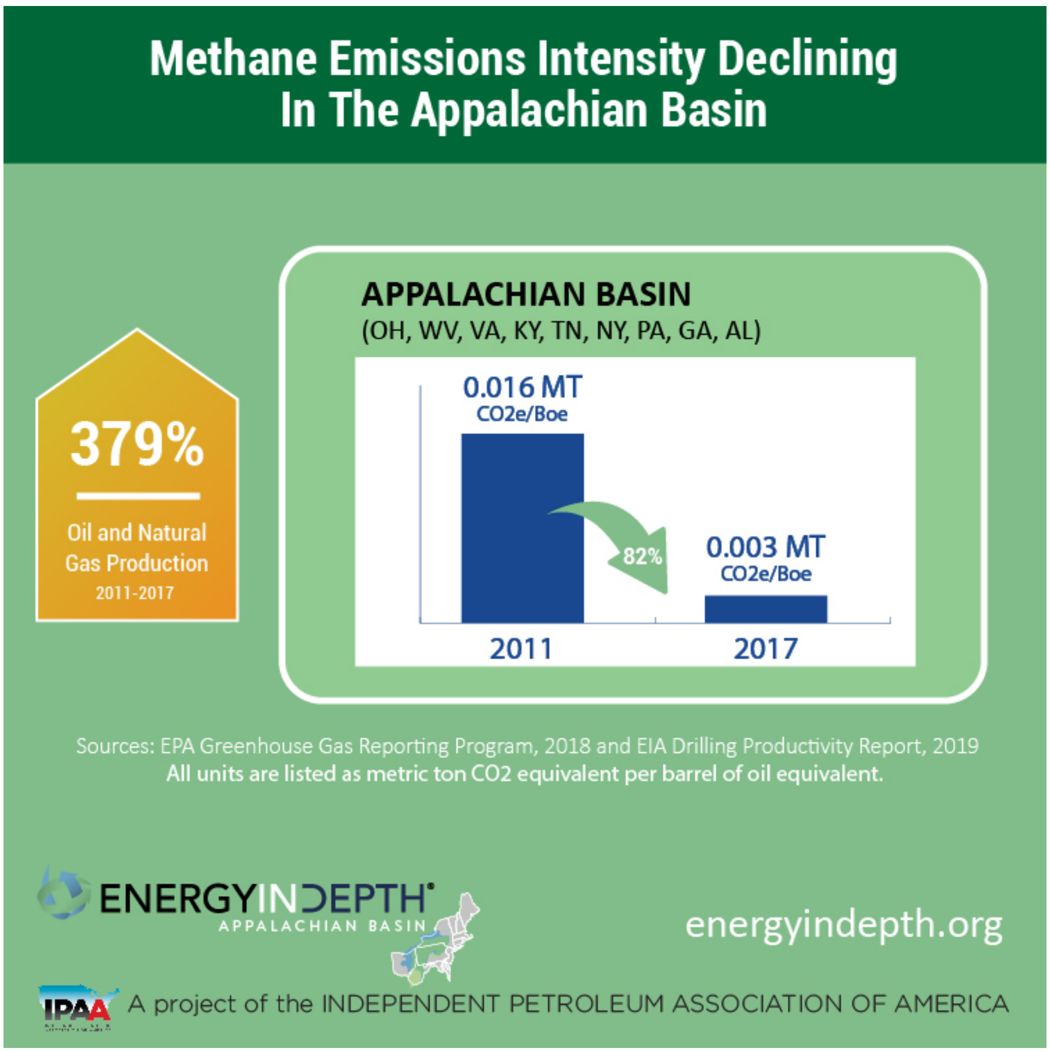
Second, of the 19 conventional wells, onsite information related to an OGI survey is supplied for 18 of them. Of these 18, the average production rate was 13.08 mcfd with calculated emissions of 1.22 mcfd or 0.05 lbs/day. Translating this value to annual emissions, it would be 0.0092 tons/year.

Third, of the 18 wells, the OGI information shows that 11 of them were characterized by having storage tank emissions from vents or hatches. Their average production rate was 13.79 mcfd with calculated emissions of 1.63 mcfd or 0.067 lbs/day. Translating this value to annual emissions results in a calculated value of 0.012 tons/year (tpy).

Fourth, the current Volatile Organic Compound (VOC) Control Techniques Guidelines (CTG) document for oil and natural gas production facilities in ozone nonattainment areas recommends its Reasonably Available Control Technology (RACT) for storage vessels apply to storage vessels "…with a potential to emit (PTE) greater than or equal to 6 tpy VOC". The assumption in this report is that the methane content of the emitted vapor is 81 percent. Consequently, the annual emissions from the well sites with tanks would be approximately 0.019 tons/year. This is approximately 0.3 percent of the threshold for regulation in the current CTG.

Fifth, to put a final perspective on the implications of this report with regard to low production wells, according to EPA, "A typical passenger vehicle emits about 4.6 metric tons of carbon dioxide per year…." or 5.07 tons per year. Applying the Greenhouse Gas Inventory Global Warming Potential to the emissions calculations for these tank-based well sites, it would take about ten of them to equal one typical passenger vehicle.

Sixth, as the following graphic shows, oil and natural gas production facilities continue to reduce their methane emissions intensity in the Appalachian basin where this report obtained its information.



7. *Assessment of methane emissions from the U.S. oil and gas supply chain (Assessment of Studies)*

This EDF report was released with great fanfare during the 2018 World Gas Conference to create the appearance of new data showing methane emissions from the oil and natural gas industry value chain. The report purports to show that emissions are far higher than those reported in EPA GHGI. The JEC then refers to this report as a linchpin of its arguments for changes to the Subpart OOOOa proposal, particularly with regard to the fugitive emissions program with a special focus on low production wells. However, probing its details provides a far different perspective.

This report is not new data. Rather, it is a reconstruction of prior data from others' studies. For example, it regurgitates the same information in the Super-Emitters study and adds some additional material from others.

As a consequence, the report suffers from no certainty regarding the quality of its data by possibly exacerbating bias and inaccuracies through incompatible sampling and data collection methodologies. It accepts as accurate everything it receives and these data have glaring deficiencies.

The predominant data that is used for the bottom-up (BU) elements of the report are – as described frequently in these comments – facility measurements that can not distinguish between fugitive emissions and allowable emissions and that are remotely sampled. These failures are demonstrated in a number of statements in the report and its supplementary materials.

For example, one of the key issues in the use of remote sampling relates to interpreting the short-term information in the context of long-term emissions. In its supplementary material, the report states:

> Measurement methods included the mobile flux plane technique …, dual tracer flux approach …, and OTM-33A, an inverse Gaussian method …. All three methods capture a snapshot of site-level emissions, with reported duration of individual plume captures of ~50 s …, 30 s to a few minutes … and 15-20 minutes ….

Consequently, using samples with time spans of 50 seconds, 30 seconds to a few minutes and 15-20 minutes, the report scales this information first to daily emissions and then to annual emissions. The approach generates an inherent and inappropriate characterization of emissions that cannot be considered accurate or valid. Further, the study presents no information regarding background levels inherent to various comingled land use activities and regional sources.

Similarly, the report makes a significant effort to try to discount this obvious emission estimating challenge by discounting the likelihood that short-term activities at the production sites could be the cause of its higher readings. However, since the researchers in their original data development chose not to work with production operations during data collection these assertions are a thinly disguised effort to rationalize the fundamental inability to understand the nature of the data. Consequently, rather than recognized that activity at production sites largely take place during daytime hours – activities such as liquids unloading, maintenance and liquid transfers – that could account for higher than normal emissions, the report attempts to argue the converse. In its supplementary materials it makes this statement:

> In addition, there is no reason to expect daytime bias in the kinds of abnormal operating conditions that are thought to characterize high-emitting production (and gathering) sites, which operate continuously. In fact, it is plausible that abnormal emissions could actually be higher at night because they are less likely to be found and corrected in the absence of operators.

Yet, the very issue that arises in the use of daytime data is highlighted in a recent NOAA study and the point was addressed in the Independent Producers initial comments by inclusion of an EID analysis of this report and are restated later in this submission.

This Assessment of Studies report – faced with trying to justify its rational for its higher emissions estimates – tries to dismiss anything that flies in the face of its biases. As it brings in its Top Down (TD) information the report includes this statement:

> An extensive aerial infrared camera survey of ~8,000 production sites in seven U.S. O/NG basins found that ~4% of surveyed sites had one or more observable high emission-rate plumes … (detection threshold of ~3-10 kg CH4/h was 2-7 times higher than mean production site emissions estimated in this work). Emissions released from liquid storage tank hatches and vents represented 90% of these sightings. It appears that abnormal operating conditions must be largely responsible, because the observation frequency was too high to be attributed to routine operations like condensate flashing or liquid unloadings alone …. All other observations were due to anomalous venting from dehydrators, separators and flares.

The report that this report references in this paragraph is the Omara Marcellus 2016 report which did – as we described earlier – at least for conventional low production wells demonstrate that the primary emissions sources were storage tanks. Here, however, the authors cannot accept the reality that storage tanks, dehydrator vents, separators and flare are the likeliest sources of emissions and must postulate some “abnormal operating conditions” because to do otherwise would undermine their singleminded focus on expensive OGI LDAR requirements.

Another point the report makes and then ignores is:

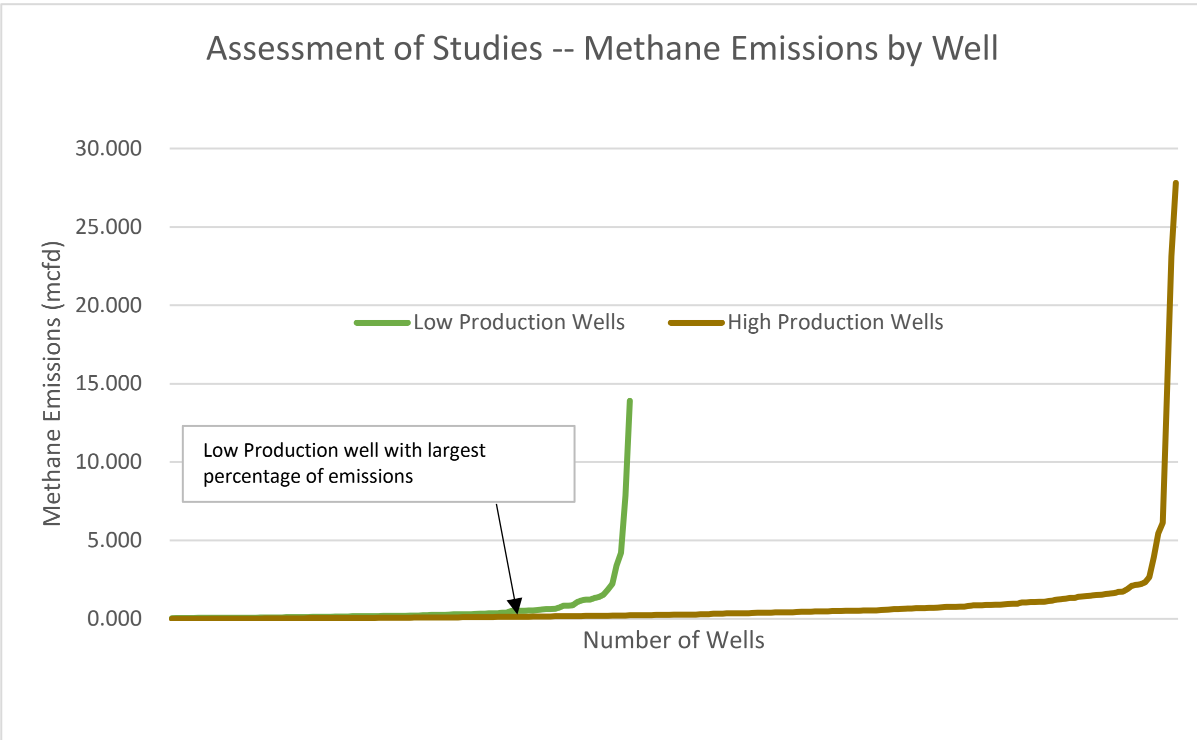
> Notably, the two largest sources of aggregate emissions in the EPA GHGI – pneumatic controllers and equipment leaks – were never observed from these aerial surveys.

This should be telling observation: *the two largest sources in the GHGI – pneumatic controllers and equipment leaks – were never observed in these aerial surveys*. But the report lets it drop while pursuing its skewed emissions estimates based on statistical manipulation of data.

These prior issues present an array of reasons why the Assessment of Studies report should have been extremely cautious about the methods it used to develop its inflated emissions estimates that the JEC has touted so frequently in its comments opposing the Reconsideration Rulemaking. The core of the Assessment of Studies emissions estimates hinges on how EDF takes the limited facility scale emissions information and kites it to national emissions.

Previously, the fundamental issue of taking short-term emissions observations and escalating them to daily and annual amounts was identified and challenged. But the more devious action taken in the report is the use of statistical tools to create emissions. Mark Twain once attributed to Benjamin Disraeli this statement, “There are three kinds of lies: lies, damned lies, and statistics.” This report falls in the last category.

The following graph presents the emissions from the well sites used in the Assessment of Studies. It tracks the same type of emissions profile as the Super-Emitter report – large numbers of wells with little or no emissions and a few wells with some emissions. And, since these data are taken for the entire facility remotely, there is no information that defines the actual sources of the emissions. Similarly, since the data is collected from 2 seconds to 20 minutes, the representation of the emissions as daily emissions is speculative at best.



This chart also demonstrates the flaw in the arguments that emissions issues should be analyzed based on the percentage of emissions related to sales. For low production wells, the highest percentage emissions well is almost at the point where it is barely discernible. It emphasizes the lack of analysis of the underlying data. In this instance, using the EDF approach of calculating its percentages based on emissions divided by sales, the result would be 24.45 percent. Any good engineer would look at this result and question losing a quarter of its sales volume. The question then would be whether something unusual was happening that created this loss. But, clearly, an EDF analyst merely sees it a data point corroborating a preconceived notion of emissions.

It also accentuates the management of the data used for the Assessment of Studies report. The authors report some data was excluded from its analysis, stating:

> And second, values reported as zero or below the detection limit (0.08 kg/h, 0.036 kg/h and 0.01 kg/h in Rella et al. (*19*), Robertson et al. (*21*), and Omara et al. (*20*), respectively) were treated as censored data points (see below). Such censoring

> applied to 78 (40%) and 18 (35%) measurements in the Barnett and Fayetteville, respectively.

This statement implies that the authors concluded that low emissions data would reduce the emissions estimates and, therefore, it was inconsistent with the intended result of the study.

All of these pieces point to a consistent conclusion regarding the validity of the Assessment of Studies report. It builds on data that is not consistent and then excludes data it does not want. But, the final aspect of its effort is telling. The key to the development of the Assessment of Studies is its statistical manipulation of its data to develop emissions values where it does not have data. Here are some important statements by the authors:

> We assume our underlying emissions pdfs are lognormal, which is expected in a system where many independent random and multiplicative events can contribute to the occurrence and magnitude of emissions

and

> Results from both tests applied to all of the datasets used directly in this work indicate that one cannot reject the null hypothesis that the site-level sample data arise from a lognormal population distribution

These are extremely weak arguments – "we assume … emissions pdfs are lognormal…."; "…one cannot reject the … hypothesis that the site-level … data arise from a lognormal population distribution."

If they are not lognormal distributions, the entire framework for the Assessment of Studies report becomes suspect. Correspondingly, looking at the nature of the site emissions data – with all of the flaws associated with the assumptions in evaluating that data – there is little to suggest it is a lognormal distribution.

These inadequacies and those described in the EID analysis of the report undermine the validity of the basis for arguing that the Assessment of Studies provides a basis for the fugitive emissions LDAR programs in Subpart OOOOa, particularly in their application to low production wells.

8. *A technical assessment of the forgone methane emissions reductions as a result of EPA's proposed reconsideration of the 2016 NSPS fugitive emissions requirements for oil and gas production sites (Omara Appendix G)*

This technical assessment was prepared by EDF to create a perception that EPA is understating the implications of its reconsideration of the Subpart OOOOa fugitive emissions requirements. Clearly, the first issue here relates to the vastly different views of the effectiveness of the fugitive emissions programs. But others are significant. For example, the assessment relies primarily on that same array of data that is used in other reports. As stated previously, fundamental issues with these data include the remote sampling nature that cannot distinguish between permitted or regulated emissions and fugitive sources and using limited time samples to create daily or annual emissions estimates. The assessment actually recognizes the challenge of distinguishing emissions.

The first issue in the assessment relates to differences between EPA calculations of the number of well sites that will be constructed between 2015 and 2025 for purposes of determining emissions changes between the current and proposed requirements. The assessment concludes that fewer wells will be drilled in the 10-year period. However, both analyses rely on assumptions that are not reflecting changes in the development of American resources. Historic wells were typically one or two wells and low production well sites producing conventional formations are more likely to continue to be. However, the larger unconventional well sites frequently include far more wells because horizontal drilling allows for the well bores to be started close to each other. Consequently, both assessments may overstate the number of well sites needed to meet future production activities.

The second issue involves the approach the assessment uses to develop emissions factors for the different well types. As it states, the assessment uses information taken from existing well sites remotely to develop its factors. This raise a number of issues.

A. Almost all of the data taken at these sites is based on existing operations that pre-date the Subpart OOOO requirements. Consequently, much of the fugitive emission arise from equipment that differ from the sites developed under those requirements (and those required under Subpart OOOOa) such as pneumatic controllers. This inevitably skews the perception of the presence of fugitive emissions.

B. The assessment concludes that EPA's use of emissions factors from the 1995 AP42 materials underestimates emissions. However, this is a highly disputable assumption since the American Petroleum Institute developed substantial new material showing that the factors overstate emissions and the failure rate of repaired equipment is longer than EPA's assumptions.

C. The assessment attempts to use information from 300 wells in the Barnett Shale to develop a reduction in total emissions to represent fugitive emissions. However, there is no basis to suggest that this approach is appropriate for all categories of wells. For example, a number of reports on low production wells suggest that the primary emissions sources at those sites are storage vessels. Storage vessel emissions are comprised of essential vents and open hatches that should be closed. A massive OGI fugitive emissions program is not necessary to address either emission.

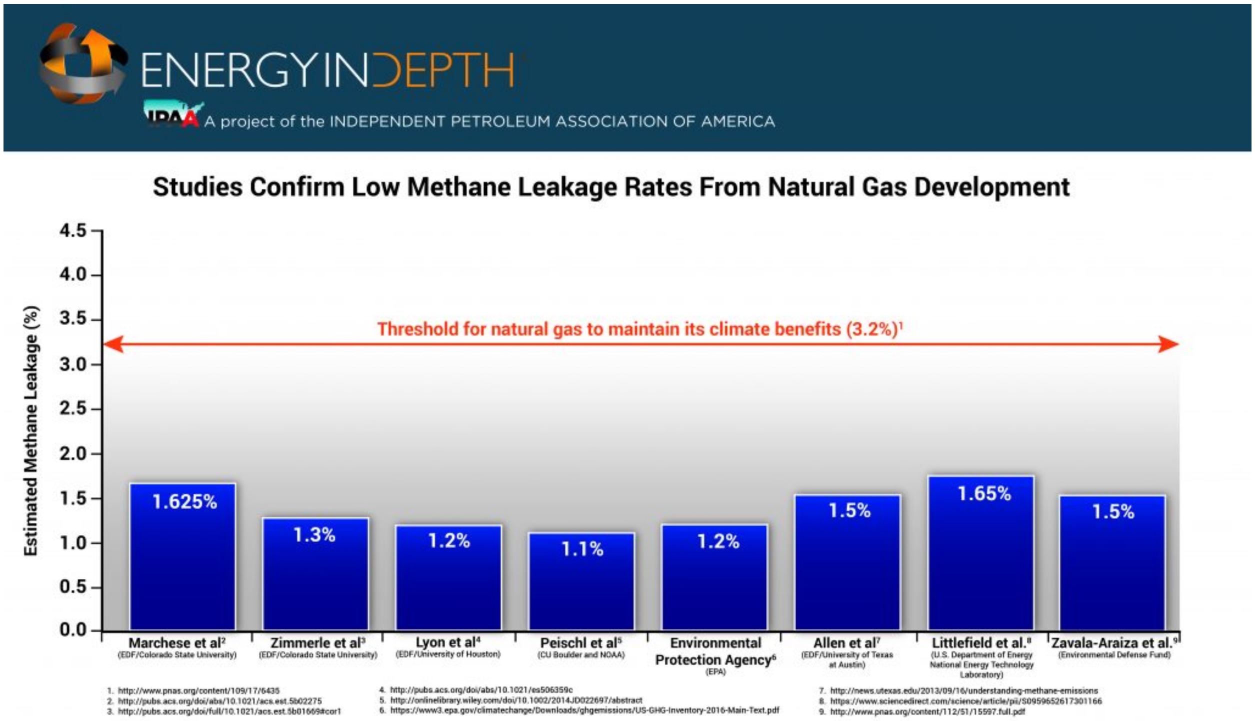
D. The assessment even states that "…fugitive emissions from storage vessels dominate site-level emissions…." But, it uses this statement to argue that EPA's emissions factor for storage tanks "…is likely a significant underestimate for these sources." However, for the new sources being considered in this assessment, storage vessels would be regulated under Subpart OOOO requiring either a vapor recovery/control system or management to keep the emissions below 4.0 tons/year. And, as described previously, storage vessels at existing low production facilities would likely be far lower than that.

Ultimately, this assessment has to be recognized for what it is – a collection of manufactured emissions estimates for the sole purpose of arguing that EPA is understating the implications of the Subpart OOOOa reconsideration when there is ample evidence that EPA has overstated both emissions and the effectiveness of its current program.

9. *Response to methane synthesis critiques (Hamburg)*

This document is a response rebutting analyses of the EDF report addressed previously. It essentially argues that those analysts are too stupid to understand the EDF report. The report responds to statements in an Energy In Depth assessment of the EDF report. The EDF analysis is provided here:

The Environmental Defense Fund (EDF) has **released a myriad of studies** on natural gas system methane emissions over the past six years that have found low leakage rates between 1.2 and 1.5 percent of production. Five such studies are featured in the following EID graphic.



So the fact that a new EDF **study** released today finds methane leakage rates of 2.3 percent — well above what EDF-led research has previously found and "60 percent higher than the U.S. EPA inventory estimate," according to the report — begs the question: What changed with regard to EDF's methodology for this study that yielded a much higher leakage estimate than its past research has shown?

Turns out, quite a lot changed, and most of the changes raise red flags regarding the study's conclusions. Not only did the authors of the new EDF study — which includes no new measurements and instead calculates national methane emissions based on past studies — opt not to use past EDF research as a basis for their emissions calculations, it relies exclusively on five far less comprehensive facility-level studies that lacked industry participation to arrive at its conclusion of higher U.S. emissions than previously reported. In contrast, an "alternative" calculation, based partially on EDF's past studies, that finds emissions in line with current EPA estimates is buried in the study's supplemental data and is not even mentioned in the report.

These are just two of several key issues regarding the manner in which EDF conducted this study that appear aimed at producing the most extreme emissions estimate possible ahead of the 27th annual **World Gas Conference** (WGC), which begins Monday in Washington, DC. Here is a deeper look at each issue.

#1. Exclusive Use of Facility-Scale Study Data Goes Against National Academy of Sciences' Recommendations and Likely Exaggerates Emissions

This study's national methane emissions estimate is based entirely on downwind, facility-based studies. From the report:

> "In this work we integrate the results of recent facility-scale BU studies to estimate CH4 emissions from the U.S. O/NG supply chain, and then we validate the results using the TD [top-down] studies."

However, a recent National Academy of Sciences (NAS) **report** aimed at improving national methane emissions inventories recommends a more comprehensive approach combining "bottom-up" measurements — both of the component- and facility-level variety — along with "top-down" measurements:

> "Coordinated, contemporaneous top-down and bottom-up measurement campaigns, conducted in a variety of source regions for anthropogenic methane emissions, **are crucial for identifying knowledge gaps and prioritizing emission inventory improvements**. Careful evaluation of such data for use in national methane inventories is necessary to ensure representativeness of annual average assessments."

EDF has conducted studies combining the comprehensive top-down/bottom-up methods recommended by NAS before. **Zavala-Araiza et al.** is the most notable example, and that study found a methane leakage rate of just 1.5 percent. Just as notably, a recent National Energy Technology Laboratory **study** based on Zavala-Araiza et al. data estimates national methane emissions at 1.65 percent. That report involved several of the co-authors of this most recent EDF study that reached much different conclusions.

The new EDF report argues that using facility-level measurements exclusively is appropriate because component-based studies can "under-sample abnormal operating conditions" such as malfunctions and large leaks. But this rationale ignores flaws with facility-level measurements that can lead to overestimation of emissions. For instance, facility-level measurements can capture episodic emissions, such as liquids unloading, and inaccurately characterize them as normal emissions that would be occurring 24 hours a day, seven days a week. The latter issue can be exacerbated when researchers lack a fundamental understanding of the facilities where they are taking measurements, which brings us to the next major issue with the study.

#2. Lack of Industry Collaboration Goes Against National Academy of Sciences' Recommendations

With regard to the ground-based, facility-level studies used as the basis for estimating national emissions in this report, the report's supplementary information document notes:

> "Sites were reported to be sampled on a quasi-random basis **without advance operator knowledge**."

Not only does EDF admit that some of the studies used did not conduct truly random sampling, it admits that industry wasn't involved in these studies on any level. This again flies in the face of recommendations made in the **NAS** report, which states:

> "[V]erifiability is the bedrock upon which inventories should be built if they are to be widely applicable to policy needs."

The lack of industry participation is surprising, considering EDF's past methane research is well known to have been a collaborative effort between EDF, academia and industry, a fact EDF has frequently **touted**. But even more surprising is EDF's justification for excluding industry from participating in this particular study. From the report:

> "Operator cooperation is required to obtain site access for emission measurements. Operators with lower-emitting sites are plausibly more likely to cooperate in such studies, and workers are likely to be more careful to avoid errors or fix problems when measurement teams are on site or about to arrive. The **potential bias** due to this 'opt-in' study design is very challenging to determine. We therefore rely primarily on site-level, downwind measurement methods with **limited or no operator forewarning** to construct our BU estimate."

Not only does EDF fail to provide a single reference to back up this claim of "potential bias" that it claims necessitated it to use the methodology highlighted above, but none of the five co-authors of this report, who were also the lead authors of past EDF methane research that was conducted in close concert with industry ,have ever publicly claimed any "bias" whatsoever. Not once.

EDF's assertion appears to be purely speculative in nature and also appears to be an excuse to use these studies as a basis for exaggerated national emission estimates.

#3. "Alternative" Emissions Estimate That Is In Line With EPA Greenhouse Gas Inventory (And Past EDF Research) Is Not Included In Report

In the supplemental materials document for this report, EDF includes the following "alternative" national emissions estimates based on source-based reports, several of which are past EDF studies.

Source: Table S3	GHGI	Source-based EDF estimate (Gg CH4/yr) – Alternative EDF estimate	Site-based estimate (Gg CH4/yr) – Primary Method
Total U.S. Oil and Gas Supply Chain	8,100 (6,800 – 10,000)	8,800 (8,400 - 9,700)	13,000 (12,000 - 15,000)

Source: Alvarez et al. supplementary materials

This “alternative” estimate finds the national methane leakage rate is 1.4 percent, which (not surprisingly) not only aligns with past EDF studies, but also the **EPA Greenhouse Gas Inventory**.

Remarkably, the data from this “alternative” estimate isn’t mentioned at all in the actual report, even though EDF notes that an extensive list of source-based studies featured in the supplemental data of the report has “dramatically improved understanding of the sources and magnitude of CH4 emissions from the industry’s operations.”

EDF also argues that its “primary” estimate — which, again, is based solely on facility-level studies — is in line with aggregate average emissions found in the following nine “top-down” studies based on emission measurements largely collected via aircraft measurements.

> “When the BU estimate is developed in this manner, direct comparison of BU and TD estimates of CH4 emissions in the nine basins for which TD measurements have been reported indicates agreement between methods…”

Table S2. Reported estimates of O/NG CH_4 emissions from aircraft-based top-down (TD) studies, listed in decreasing order of natural gas production. Italicized values were calculated in this work; shaded rows indicate a second independent, statistically consistent set of reported measurements in two basins (not used directly in this work in favor of the more recent results based on more intensive sampling). Uncertainties are 2-sigma values calculated from reported uncertainties.

TD survey area	Reference	Date Sampled (Month/yr)	Days/flights/ downwind transects	NG production (bcf/d)	% CH_4 in NG	Upwind Background Method*	Total CH_4 Flux (Mg/h)	O/G apportionment method†	O/NG CH_4 flux (Mg/h)†	Production normalized emission rate$
Haynesville	Peischl (*51*)	6/2013	1/1/3	7.7	86%	UTA	80 ± 54	SE	*73 ± 54*	*1.3%*
Barnett	Karion (*71*)	3 & 10/2013	8/8/17	5.9	89%	DL	76 ± 13	E	60 ± 11	*1.4%*
NE PA	Barkley (*67*)	5/2015	4/4/7	5.8	95%	MUT	20 ± 17	SE	18 ± 14	*0.40%*
NE PA	Peischl (*51*)	7/2013	1/2	N/A	95%	UTA	15 ± 12	SE	13 ± 12	*0.30%*
San Juan	Smith (*52*)	4/2015	5/5/5	2.8	83%	DL	62 ± 46	N	*57 ± 54*	*3.0%*
Fayetteville	Schwietzke (*47*)	10/2015	2/2/4	2.5	97%	UTSV	31 ± 8	SE	27 ± 8	*1.4%*
Fayetteville	Peischl (*51*)	7/2013	1/1/2	N/A	97%	UT	39 ± 36	SE	35 ± 32	*1.9%*
Bakken	Peischl (*49*)	5/2014	3/3/5	1.9	47%	DL	28 ± 10	SE	27 ± 13	*3.7%*
Uinta	Karion (*69*)	2/2012	1/1/1	1.2	89%	UT	56 ± 30	S	55 ± 31	*6.6%*
Weld	Petron (*70*)	5/2012	2/2/3	1.0	79%	UT	26 ± 14	S	19 ± 14	*3.1%*
W Arkoma	Peischl (*51*)	7/2013	1/1/1	0.37	96%	UT	33 ± 30	S	26 ± 30	*9.1%*
9-basin total				29			410 ± 87		360 ± 92	1.8 ± 0.5%¶

* Upwind background methods: UT=upwind transect; UTSV = spatially variable upwind transect; UTA=upwind transect with adjustments to account for methane above background that flows into a region; DL = downwind lateral plume edges; MUT = model-assisted upwind transect

† Apportionment methods: S= subtraction of inventory-based estimates of non-O/NG sources; E = ethane; SE = subtraction with ethane as qualitative check; N = none

$ Methane emitted normalized by methane produced

¶ Production weighted

Source: Alvarez et al. supplementary materials

#4. Attempts to Discredit Study That Finds Misrepresentation of Episodic Events Can Lead to Inflated Emissions Estimates Via Daytime Bias

Another factor that can lead to facility-scale measurements overestimating actual normal emissions is the fact that such methods are conducted in the daytime and, thus, can capture emissions from episodic events — such as liquids unloading — that are conducted during the day and inaccurately extrapolate them as if they are constant. This fact was further confirmed by a recent peer-reviewed NOAA study of the Fayetteville Shale **covered** by EID last year.

Perhaps anticipating that 2017 study would be used to call this new EDF report's conclusions into question, EDF attempts to discredit the NOAA study in the paper:

> "[W]e consider unlikely an alternative hypothesis that systemically higher emissions during day-time sampling cause a high bias in TD methods."
>
> "[T]here is no reason to expect daytime bias in the kinds of abnormal operating conditions that are thought to characterize high-emitting production (and gathering) sites, which operate continuously. In fact, it is plausible that abnormal emissions could actually be higher at night because they are less likely to be found and corrected in the absence of operators."

The above claim is directly contradicted by the following, which acknowledges the validity of the NOAA Fayetteville study, but claims it isn't relevant to other basins.

> "O/NG emissions are systematically higher during daytime hours when TD and BU measurements have been made, and lower at night. This situation was reported for the Fayetteville Shale but appears to be unique because the effect is caused by manual liquids unloadings, which represent a much higher fraction of total production emissions than in any other basin."

The fact is, events such as liquid unloadings *are* common in other basins and downwind measurements, such as the ones used as the basis for this EDF analysis, do tend to be higher because they are conducted during the day.

#5. Despite EDF's Alarmist Characterizations, Natural Gas' Climate Benefits Remain Clear

The report claims the oil and natural gas development emissions level estimated in this report combined with carbon emissions from current natural gas combustion is having the same climate impact as coal in the short term (20-year timespan):

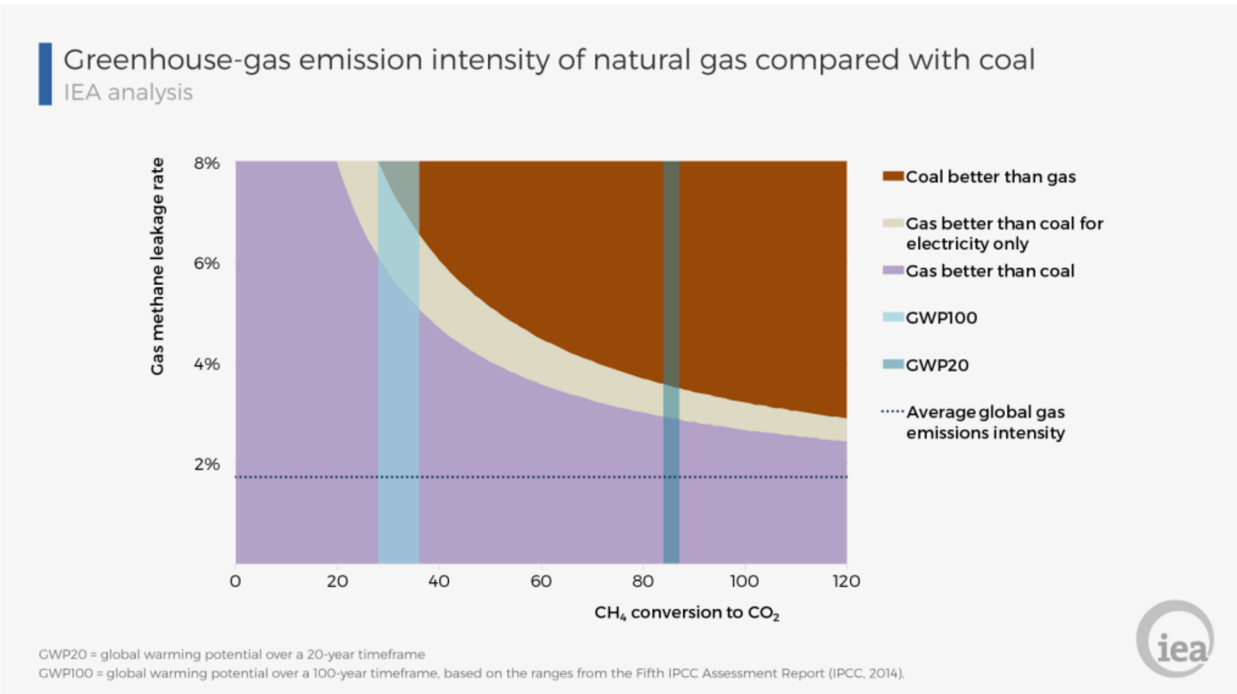
> "Indeed, our estimate of CH4 emissions across the supply chain, per unit of gas consumed, results in roughly the same radiative forcing as does the CO2 from combustion of natural gas over a 20-year time horizon (31% over 100 years). Moreover, **the climate impact of 13 Tg CH4/y over a 20-year time horizon roughly equals that from the annual CO2 emissions from all U.S. coal-fired power plants operating in 2016 (31% of the impact over a 100-year time horizon).**"

But as alarming as that claim might be, it is essential to note that natural gas maintains clear climate benefits over other traditional sources even at much higher leakage rates than purported by this study.

A recent hydraulic fracturing issues brief published by Washington D.C.-based environmental think tank Resources for the Future (RFF) **notes**:

> "If more than about 4% of the natural gas produced in the United States is emitted as methane (rather than being burned), the climate benefits of gas's displacement of coal disappears over a 20-year time frame. If the time frame is 100 years, the leakage rate would have to be more than 8% for natural gas to be a climate loser relative to coal."

The following International Energy Agency (IEA) graphic illustrates RFF's point, showing natural gas maintains its climate benefits even at high leakage rates and regardless of time-frame considered.



Conclusion

This EDF study spends an inordinate amount of time explaining *why* its conclusions are plausible rather than explaining *how* it reached its conclusions. And it's clear why — once one digs into the report's supplemental information, it's clear that the conclusions are based on some pretty shaky assumptions and speculation that runs counter to established and/or recommended best practices for such research.

But at the end of the day, the EDF study is not only an outlier in terms of the overall body of current methane research — it's also an outlier with regard to EDF's collective methane research, which has consistently found leakage rates between 1.2 and 1.5 percent. In the meantime, EPA **data** show oil and gas methane emissions have declined 14 percent since 1990 even as oil and natural gas production have skyrocketed. Combined with the fact that increased natural gas use has helped contribute to the best air quality of the modern era and the

> lowest carbon emissions in 25 years, it is clear that the shale revolution has been a win-win for the economy and environment.

As addressed in specific comments on the EDF report, despite EDF's characterization of the report as "…the culmination of an extensive amount of research…examining methane emissions from the U.S. oil and gas supply chain", the material is an aggregation of various reports that fail to change the reality that the data suffers from the limitations that it is dependent on remote sampling that cannot distinguish sources and that it estimates daily or annual emissions from short term data collection.

In addition to relying on the studies above, the JEC attempts to further justify its positions by identifying new information that it believes points to support. These three items are, in reality, as flawed as support documents as the studies the JEC relies on.

1. *Very Strong Atmospheric Methane Growth in the Four Years 2014 – 2017: Implications for the Paris Agreement*

The environmental activists argue that:

> A new paper approved for publication by the American Geophysical Union indicates that there has been rapid growth in atmospheric methane since 2007, including "remarkable growth" in methane concentration between 2014 and 2017. One reason that the paper finds for this increase in atmospheric methane is from "very large" emissions of methane from the oil and natural gas sector. The paper concluded that "[r]educing methane emissions is feasible, *especially from fossil fuel sources*, and would have rapid impact on the global methane burden."

New research on rising global methane levels is much more complex than the environmental activists suggest in their comments. While, the report details that oil and natural gas is still a source of methane, it also explains that "fossil fuel emissions are falling as a proportion of the total methane emission." Further, the study notes,

> "However, there is evidence (Schwietzke et al., 2016) that natural gas emissions per unit of production have declined significantly in recent years, and rapid improvements and investment in leak detection and reduction have likely cut the percentage of gas leaked from gas industry production facilities."

More importantly, and as media reported, biogenic sources of methane are thought to be a more likely cause of the increases. Lead author of the study, Professor Euan Nisbet of Royal Holloway, University of London, told the *Guardian*, "We have only just started analysing our data but have already found evidence that a great plume of methane now rises above the wetland swamps of Lake Bangweul in Zambia." Notably, Zambia is not a country with significant – if any – oil and gas production. The *Guardian*, which has vocally supported a "Keep It In the Ground" agenda with regard to fossil fuels in recent years, had a much different take on the study's findings than the activists:

> "**Studies suggest these increases are more likely to be mainly biological in origin**. **However, the exact cause remains unclear**. Some researchers believe the spread of intense farming in Africa may be involved, in particular in tropical regions where conditions are becoming warmer and wetter because of climate change. Rising numbers of cattle – as well as wetter and warmer swamps – are producing more and more methane, it is argued."

The activists' typical approach of pulling statements out of context here is clear.

More recently, a report by National Oceanic and Atmospheric Administration (NOAA) and University of Colorado scientists entitled, "Long-Term Measurements Show Little Evidence for Large Increases in Total U.S. Methane Emissions Over the Past Decade", calls into question some of the fundamental approaches to assessing methane emissions that have led to excessive emissions estimates. That report summarizes the issues as follows:

> In the past decade, natural gas production in the United States has increased by ~46%. Methane emissions associated with oil and natural gas productions have raised concerns since methane is a potent greenhouse gas with the second largest influence on global warming. Recent studies show conflicting results regarding whether methane emissions from oil and gas operations have been increased in the United States. Based on long-term and well-calibrated measurements, we find that (i) there is no large increase of total methane emissions in the United States in the past decade; (ii) there is a modest increase in oil and gas methane emissions, but this increase is much lower than some previous studies suggest; and (iii) the assumption of a time-constant relationship between methane and ethane emissions has resulted in major overestimation of an oil and gas emissions trend in some previous studies.

Moreover, to supplement the point that industrial actions are reducing methane emissions, as described previously, in the U.S. new information demonstrates that methane emissions intensity is declining.

2. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2017*

With regard to the Green House Gas Inventory, the activists state:

> Furthermore, EPA's latest draft greenhouse gas inventory, released February 12, 2019, shows that methane emissions increased slightly for the oil and gas sector between 2016 and 2017. While EPA's inventory significantly underestimates methane emissions from the oil and gas sector, as discussed *supra* Section II, the latest draft inventory continues a pattern showing that overall methane emissions remain unacceptably high.

The activists carefully address emissions changes only from 2016 to 2017. Energy In Depth addressed the Inventory more fully in the following assessment:

> U.S. greenhouse gas emissions fell significantly from 2005 to 2017, even while oil and natural gas production **skyrocketed**, according to the Environmental Protection Agency's **draft 2019 greenhouse gas inventory (GHGI)**.
>
> The draft GHGI data show total U.S. CO2 decreased nearly 14 percent, while methane emissions were reduced by more than 4 percent since 2005. Meanwhile, U.S. oil and natural gas production increased more than **80 percent** and **51 percent**, respectively, according to the Energy Information Administration.

CO2	1990	2005	2013	2014	2015	2016	2017
Natural gas systems	30.0	22.6	25.1	25.5	25.1	25.5	26.3
Petroleum systems	8.9	11.6	25.2	29.7	31.7	22.2	23.3
Combined	38.9	34.2	50.3	55.2	56.8	47.7	49.6
Methane							
Natural gas systems	193.9	171.9	166.3	165.8	167.8	164.7	166.2
Petroleum systems	42.1	36.7	41.6	42.1	39.5	38.2	37.7
Combined	236.0	208.6	207.9	207.9	207.3	202.9	203.9
Total U.S. CO2	**5,122.0**	**6,131.5**	**5,524.0**	**5,574.9**	**5,427.0**	**5,310.5**	**5,279.7**
Total U.S. Methane	**780.8**	**692.1**	**664.0**	**663.1**	**661.8**	**653.4**	**663.3**

Source: Table ES-2, EPA draft "Inventory of U.S. Greenhouse Gas Emissions and Sinks," February 2019; Data: million metric ton CO2 equivalent

The activists also dismiss the information that they report by referring to their recurring analyses that the Inventory underestimates emissions. However, as described above, the basis for alleging higher emissions is based on limited and flimsy analyses. Moreover, while the total methane emissions that are reported in the Inventory amount to about 3.86 percent of the total inventory, the contribution from the oil and natural gas production would be 1.2 percent.

3. *Plugging the Leaks: Why Existing Financial Incentives Aren't Enough to Reduce Methane*

The activists pull from this report the following assessment:

> Finally, a new policy brief from the University of Pennsylvania highlights the need for standards to reduce fugitive methane emissions from the oil and gas sector because the value of recovered product alone may be lower than the cost to control the emissions. In other words, often industry is not economically incentivized to control the emissions based on its own cost-benefit analysis. Capturing these emissions is important because of the social damage from climate change and health and safety harms from emissions, which operators do not factor into their own cost-benefit analysis. Because industry does not take these societal costs into account, the need for strong federal action is clear as "global damages reflect real economic risks to the United States, as climate change will impact the global economy."

There are two fundamental issues here that arise on a recurring basis. The first relates to the assessment of cost-benefit analysis in the regulatory arena, particularly with regard to low production wells. Most cost-benefit analyses develop assessments based on valuing the cost of the regulatory requirement and the amount of the recovered emissions. It produces a value in dollars per unit of emissions, e.g., $/ton or $/mcf. What these cost-benefit analyses fail to address are the economic implications for a facility including their operating costs. The Independent Producers comments have submitted assessments regarding how the failure to look at the full implications of regulations can distort conclusions about their "benefits" when in fact they will cause operations to cease.

The second issue relates to the development of social benefits from regulations in the context of global implications. The issue of "social cost" calculations is a complicated one. Developing social cost values relies on a wide variety of assumptions that can be sound or speculative. If these values are not well founded and reliable, social cost calculations can be manipulated to produce whatever value is needed to generate a "cost effective" regulations. Essentially, the process becomes a "black box" that produces a supportive result.

In 2015, NERA Economic Consultants addressed the implications that differing assumptions can have on social cost benefit determinations as a part of comments on the original proposal of Subpart OOOOa regulations. It stated in part:

> The U.S. Environmental Protection Agency (EPA) proposed emission standards for methane (CH4) and volatile organic compounds from new and modified sources in the oil and natural gas sector (referred to as "the Proposed Rule" in this report) on August 18, 2015. Accompanying this Proposed Rule is a Regulatory Impact Analysis (RIA) that is required under Executive Orders 12866 and 13563 for all major rulemakings from Executive Branch agencies. The RIA contains estimates of the net benefits of each of several options that the Proposed Rule is considering, which are equal to each option's estimated benefits minus its estimated compliance costs.
>
> Our comments address technical issues with the RIA's monetized benefits estimates, which are entirely based on potential reductions in future climate change due to CH4 reductions, using a concept called the social cost of methane (SC-CH4). We demonstrate that EPA's estimates of the benefits are: 1) highly uncertain and very likely overstated; and 2) lack the appropriate peer review that is necessary for use in supporting regulatory policy. We also explore the implications of these issues with the Proposed Rule's net benefits estimates, and find they are far more likely to be negative than positive.
>
> More specifically:
>
> - We conclude that the RIA's estimates of benefits from CH4 reductions using its SC-CH4 estimates are highly uncertain and likely overstated for multiple reasons:
>   - The EPA's SC-CH4 estimates are based upon a single study (Marten *et al.*, 2014) whose estimates are significantly greater than, and inconsistent with, available estimates in other published papers (see Section II for a summary of the rest of the literature).
>   - EPA relies on SC-CH4 estimates that reflect global benefits rather than domestic benefits, a practice that is contrary to the Office of Management and Budget's (OMB's) *Circular A-4* (OMB, 2003) and inconsistent with the theoretical underpinnings of benefit-cost analysis that endow the method with its ability to guide a society towards policies that will improve its citizens' well-being. *Circular A-4* calls for use of domestic benefits, and notes that any estimates of non-domestic benefits should be presented separately. EPA's use of global SC-CH4 benefits estimates (and failure to

even present domestic benefits, which are readily obtained The RIA includes a 2.5% discount rate in its range of benefits, which is inconsistent with the short atmospheric lifespan of CH4. Its inclusion overstates the upper end of EPA's SC-CH4 estimates, and hence its net benefits.

  - Marten *et al.* (2014) have used assumptions regarding indirect effects on radiative forcing from changes in tropospheric ozone and stratospheric water vapor levels that lack clear support from the scientific literature. This assumption, which is uncertain and not validated, could be a substantial source of overstatement in EPA's SC-CH4 estimates. For example, compared to a zero indirect effects assumption, it increases EPA's SC-CH4 estimate by about 36% (when using a 3% discount rate).
  - EPA's SC-CH4 estimates are based on an average of five socioeconomic scenarios, four of which assume no incremental policies to reduce emissions in the future (also known as "business as usual" scenarios). Use of scenarios that assume no future emissions control policies to estimate the benefit of reducing a ton of emissions in the near-term overstates the SC-CH4 estimates.

- The absence of a full scientific peer review of the methodology behind EPA's SC-CH4 estimates calls into question the reliability of all of the RIA's estimated benefits and net benefits. We conclude more extensive peer review is especially warranted in this particular case for several reasons:
  - The integrated assessment models (IAMs) that were used to compute EPA's SC-CH4 estimates were modified in a significant manner that has not been reviewed by the original model developers. Other researchers working in this field have not had a chance to concur or disagree with the methodological changes and alternative input assumptions that EPA believes cause its SC-CH4 estimates to be so much greater than other published estimates.
  - The development of new SC-CH4 estimates by modifying pre-existing IAMs to make "standardized" calculations is inconsistent with the concept of using multiple existing models to identify the range of uncertainty in the best-available science-based estimates.
  - EPA conducted an internal peer review process and the paper upon which it has relied (Marten *et al*. 2014) has been published in a peer-reviewed journal. However, those two types of reviews do not replace the need for a more rigorous independent scientific review in light of the types of changes described above. Additionally, EPA's internal reviewers lacked consensus on the use of the paper's SC-CH4 estimates for evaluation of major regulations.

To provide a quantitative assessment of the sensitivity of the RIA's estimates of benefits and net benefits to the technical issues that we have identified, we have re-estimated the SC-CH4 values under several alternative assumptions that we consider more reasonable. These alternative calculations include 1) eliminating from consideration the 2.5% discount rate, 2) limiting benefits to a domestic geographic scope, 3) using alternative assumptions regarding the indirect effects on radiative forcing, and 4) eliminating "business as usual" emissions projections as the reference point for computing future damages from a ton of incremental emission that would occur today. EPA's assumptions on these matters are discussed in Section III, along with our explanations for why our alternative assumptions are more reasonable for estimating SC-CH4 for use in a Federal RIA. All of our alternative SC-CH4 calculations have been made using the same IAMs that Marten *et al.* (2014) used to make their SC-CH4 estimates.

Figure 1 provides a summary of how the EPA's SC-CH4 estimates would change based on assumptions we consider either more reasonable or subject to too much uncertainty for EPA to rely on a single point estimate. The first row shows the range of SC-CH4 included in the RIA based on mean values using 2.5%, 3.0%, and 5.0% discount rates.9 Each subsequent row includes a revised range based on different cases we constructed to address some of the technical issues we identified in EPA's SC-CH4 estimates. Case A removes from consideration the 2.5% discount rate because it is not appropriate given that the shorter atmospheric lifespan of CH4 implies that the resulting climate benefits are not intergenerational. Cases B, C, and D then use a range of discount rates from 3% to 5%, while layering on additional alternative assumptions. Case B shows the range of SC-CH4 estimates when limited to a domestic geographic scope. Case C removes the assumption EPA made on a 40% enhancement of radiative forcing due to indirect atmospheric effects (in addition to the change for Case B). Case D incorporates the same changes as in Case C, but also ensures the baseline emissions projection provides consistency between future emissions control policies and the current emissions reduction effort that is implied if the SC-CH4 is to be used to make near-term emissions reduction decisions.

As Figure 1 shows, using all the alternative assumptions produces SC-CH4 estimates that are as much as 90% and 94% lower than EPA's SC-CH4 estimates for 2020 and 2025, respectively.

Figure 1. Alternative Estimates of SC-CH4 Reflecting Key Methodological Uncertainties

		SC-CH4, $ per tonne of CH4 (2012$) *(% Change Relative to RIA Range)*			
		2020		2025	
Case	Description	Min	Max	Min	Max
RIA	RIA Option 2 (2.5%, 3.0%, and 5% discount rates)	587	1,721	702	1,900
A	RIA Option 2 (3.0%, and 5% discount rates)	587 0%	1,309 -24%	702 0%	1,508 -21%
B	Domestic (U.S.) specific SC-CH4 values averaged across all socioeconomic scenarios from PAGE and FUND models.	106 -82%	210 -88%	130 -81%	248 -87%
C	Domestic (U.S.) specific SC-CH4 values averaged across all socioeconomic scenarios from PAGE and FUND model without the indirect effects.	69 -88%	141 -92%	84 -88%	158 -92%
D	Domestic (U.S.) specific SC-CH4 values for the 5th Scenario from PAGE and FUND model without the indirect effects.	58 -90%	99 -94%	69 -90%	115 -94%

Note: The Min and Max values span different discount rates, EPA's Low and High total costs, and climate benefits. For Cases B, C, and D, we do not report U.S-specific SC-CH4 estimates from the DICE model because it is a global model and does not include regional details (see Section III.2 for discussion).

The percentage changes in the SC-CH4 estimates would directly translate to percentage changes in the overall estimated benefits since there is not any change associated with the assumed tons of CH4 reductions. Thus, we find that the Proposed Rule is likely to result in net costs, rather than net benefits….

These comments demonstrate the substantial challenge of decision making utilizing a social cost framework for climate related regulations. Analysts who assess policies like the allegations in the activist referenced report produce conclusions that cannot be validated since they rely on determinations that are as speculative as social cost calculations.

Joint Environmental Coalition Supplemental Filing – February 21, 2019 – Criticisms of Industry Comments

The JEC submitted a supplemental filing on February 21, 2019, that asserted a number of criticisms of industry comments, many of which attack statements or information submitted by the Independent Producers. A number of these allegations are addressed below.

1. *Demand for EPA to make all new data submitted during comment period available to public and reopen comment period*

The JEC demands in its Supplemental Filing that EPA make all new data submitted in the comment period available to the public and reopen the comment period to address this additional data. The purpose of this demand is clearly to delay EPA's action to address the proposed reconsideration of Subpart OOOOa. Ironically, when comments submitted by EDF on the "super-emitters" study during the comment period on the Subpart OOOOa resulted in the removal of the proposed low production well exclusion, the environmentalist were not crying foul. Not only should the concept of "what is good for the goose is good for the gander" apply, nothing prohibits EPA from relying on information submitted in response to an issue/topic raised in the proposed rule. The Independent Producers believe EPA needs to move forward on its proposed changes to Subpart OOOOa expeditiously.

2. *Reduction in Monitoring Frequency at Well Sites remarks rely on flawed reports*

The JEC criticizes comments addressing the validity of EPA's proposal to extend the monitoring frequency for both large wells and low production wells. Significantly, the basis for these criticisms is reliance on both the Assessment of Studies and Omara Appendix G reports. Both of these reports are essentially reassessments of the same information and reflect the same problems of remote, short-term data. Consequently, while they manipulate the data to create illusions of high emissions, these conclusions are no more valid than the estimates the JEC criticizes. Moreover, these data are based on facilities that largely preceded the requirements of Subpart OOOO and therefore do not reflect the technologies required by those regulations and their emissions reductions.

3. *IPAA comments on super-emitter study – Zavala, Omara 2016, Appendix A*

The JEC challenges the Independent Producers criticisms of the Super-Emitters report, offended by the characterization of the report as "specious". Specious can be defined as "having a false look of truth or genuineness". Recognizing that a key purpose of the JEC is the ultimate use of Subpart OOOOa to terminate the 770,000 low production wells in the United States using the nationwide existing source requirements of Section 111(d) through the application of costly OGI based fugitive emissions regulations casts all of the analytical efforts funded by or conducted by the JEC members into a clear light. Their efforts are targeted to this end result and their reports are tools to get there. In this context they must *appear* to be genuine, but their efforts are biased. They are at their core, specious.

The Independent Producers look to the key ingredients of the Super-Emitter report for corroboration. First, to prevent a discussion on the actual volumes of emissions, the report generates its percentage of production basis. Second, in creating this approach, it distorts the calculation by using a false basis to increase the percentage number. Third, it chooses to present only a portion of the data to elevate the appearance of higher percentage emissions. Fourth, it chooses to use a mathematical presentation that "flattens" data to make it look more a straight line. These are choices made to create a result to target low production operations.

The JEC argues that the Independent Producers criticize the Super-Emitter report for aggregating data from different studies. The criticism, if fact, is that these studies were not designed to evaluate low production wells, that those wells are merely components of a larger study, and that the short-term collection of general data does not present a picture of low production wells to use as a basis for their regulation. The JEC obliquely acknowledges this reality in stating:

> We agree that site-level measurements include intentional, vented emissions in addition to fugitive emissions.

However, it then argues that its solution is a costly LDAR program. Conversely, the Independent Producers believe that such a costly LDAR program would be a death blow for these small business facilities and that more analysis is needed before sentencing them to that fate.

The JEC also directs attention to the Omara Marcellus 2016 report touting another of its percentage of production emissions conclusions. However, as described above, a closer look at this report and its information on low production wells finds that storage tanks were the dominant emissions sources at the 60 percent these facilities but their emissions would fall well below the threshold for regulation under the current CTG. Equally important, an OGI LDAR program is not needed to find open thief hatches on tanks.

4. *Reference to 1000 well study – Appendix G*

The JEC further turns to its Assessment of Studies document for another attack on low production wells, emphasizing its 1000 wells analysis and its calculation of higher emissions values based on this report.

As described previously in evaluating the Assessment of Studies document, these conclusions are wholly flawed. First, while the Assessment of Studies document considers 1000 wells, not all of these are low production wells. Second, a substantial share of the 1000 wells are the same wells that were in the Super-Emitters report. Third, the Assessment of Studies document does nothing to quality control this old data to determine what it sampled or how accurately. Fourth, contrary to the JEC statement, these data do not distinguish between fugitive and permitted emissions and suffer from all of the limitations of taking short term data and extrapolating it to daily and annual values. Fifth, the Assessment of Studies appears to have eliminated all of the zero and low emissions sites from its analysis thereby skewing the emissions estimates high. Sixth, the entire report is an exercise in generating emissions values where data does not exist.

Using this faulty, conclusion driven Assessment of Studies report as a basis to judge the regulation of low production wells is wholly inappropriate.

5. *Carbon Limits*

The JEC alleges that the Independent Producers misinterpret the Carbon Limits report countering that the report shows that OGI LDAR programs are cost effective in the aggregate. The Independent Producers were not concerned about the aggregate conclusions; the focus was on low production wells. Here, there were several differences. First, as noted previously, like most other analyses and EPA's calculations, the value of recovered methane is too high – \$4.00/mcf versus \$1.67. Second, the JEC fails to mention that the Carbon Limits report found that fugitive emissions at well sites represented only 17 percent of their methane emissions. These emissions are presumably the target of an OGI LDAR program. Third, this reality likely leads to the Carbon Limits report's assessment that an infrared camera based LDAR program is not cost effective for 85 percent of well sites based on the \$4.00/mcf methane value and a larger percentage if a more realistic value (e.g., \$1.67/mcf) were used.

6. Fort Worth comments

The JEC criticizes the Independent Producers assertions that the use of the Fort Worth dataset to characterize low production wells. The JEC then goes on to state:

> Environmental Commenters agree that it would be arbitrary and capricious for EPA to rely on this evidence as a sole basis for subcategorizing low production wells and developing a separate low-production well model facility. *See* Joint Environmental Comments at 94-100. However, uncertainties regarding the representativeness of the Fort Worth dataset for low-production wells indicates that EPA lacks sufficient data to regulate low-production wells as a separate category, *not* that EPA may exempt these wells from regulation, as IPAA argues. These concerns instead underscore that EPA lacks meaningful evidence to contravene its conclusion in the 2016 Rule that "a low production well model plant would have the same equipment and component counts as a non-low production well site." 81 Fed. Reg. at 35,856. Indeed, the Fort Worth dataset shows that these low producing wells have high absolute emissions and component counts similar to those in EPA's non-low production model facility. *See* Joint Environmental Comments at 97-99.

This analysis turns the entire concept of regulation on its head. Under its reasoning, the most appropriate basis for regulating would be when EPA knows nothing about the emissions from a potential regulated source. Returning to the 2016 Subpart OOOOa rule, EPA initially chose to exclude low production wells from regulation. It then relied on the specious Super-Emitter study to argue that regulation was necessary based not on emissions information but on purported equivalency of component counts. Now, when EPA attempts to recognize that distinctions exist between large and low production wells, the JEC argues that it should not and then tries to cover its argument by alleging that the component counts really are not that different.

The points that the Independent Producers raise relate to the challenge facing EPA in trying to characterize low production wells using the 25 Fort Worth wells. The Independent Producers do not believe that component counts are a valid basis for developing emissions analyses for low production wells. However, if EPA chooses to go that route, it must have a more substantive basis than 25 wells in one basin. This is particularly significant with regard to the implications of Section 111(d) that would affect 770,000 wells nationwide. In the Independent Producers comments, the flaws in the use of the Fort Worth wells are laid out relating to questions about their representativeness, whether they are in fact low production wells and the validity of the emissions factors that drove the emissions estimates. These flaws generate the need for EPA to develop a more thorough and accurate understanding of low production wells.

In that context, the JEC argument that low production well regulation should go forth and expand perhaps 400 times the annual rate of affected facilities that EPA projects in Subpart OOOOa demonstrates its true intent to cripple and destroy America's low production wells.

7. IPAA low production well statements

The JEC further challenges the Independent Producers submission of information on component counts for low production wells across a broad spectrum of states. As the JEC states:

> IPAA itself admits this data is "not intended to be presented as statistically accurate or fully representative of the population of low production wells."

The purpose of submitting this information must be considered in the context that it was intended. As the Independent Producers have stated in submitted comments:

> The EPA should defer any fugitive emissions regulations of low production wells until it obtains information on emissions from low production wells. Specifically, the EPA should first determine whether a low production well program is appropriate and cost-effective, and the design a program based on accurate emissions information from low production wells. The Department of Energy ("DOE") is initiating a research effort to provide specific low production well emissions information that can inform these decisions and actions.

The information submitted in the Independent Producers comments on component counts at low production wells across the nation was generated to emphasize to EPA that creating a model facility for the purpose of making a regulatory assessment required a far broader framework than the 25 Fort Worth wells. Necessarily, the information had to be voluntarily provided by small business operators in the limited time frame of the public comment period. The Independent Producers do not and would not expect EPA to assume it has the kind of quality assurance that EPA would apply to data for regulatory development. However, it does demonstrate that there are substantial differences in the component counts of low production wells – and substantially different counts than the 25 Fort Worth wells. The burden is on EPA to support its regulations of low production wells. The previous Administration relied on information supplied on limited data that has since been proven not representative, if not misleading or unreliable.

8. *Low production well – initial versus ongoing production*

The JEC challenges the concept of classifying low production wells on the basis of current production rather than initial production. The JEC argues:

> Such a classification would create an unworkable standard for both EPA and operators, as monitoring frequencies for individual wells would continually be in flux.

In fact, this type of classification decision on low production wells is made annually by hundreds of thousands of wells as a part of their determination as marginal wells for federal income tax purposes. The Independent Producers recommend in their initial comments an approach to address the definition of a low production well using the federal income tax code as a basis that would be far fairer and more workable than the approach in the proposed Subpart OOOOa reconsideration.

Joint Environmental Coalition Comments

The JEC also filed initial comments dated December 17, 2018. These comments raise a number of issues that distort the nature of methane emissions, the effectiveness of regulations and industry positions.

1. *Methane Emissions Understated (Page 9)*

The JEC submits its information on methane emissions but it does so without any context. For example, it reports the GHGI inventory values for natural gas and petroleum systems. Yet, without understanding these values in context they are meaningless. The JEC wants to suggest that a regulatory system would eliminate these emissions but that cannot happen.

First, these emissions estimates are developed for the full value chain – production through distribution to end users. Subpart OOOOa does not regulate all of these elements.

Second, these emissions need to be considered in the context of the entire GHGI. The Independent Producers address the exploration and production components of the GHGI. These amount to about 1.2 percent of the total GHGI.

Third, even if the revised hypothetical emissions values created by the JEC, were remotely accurate, the exploration and production components would still be less that 2.5 percent of the GHGI. However, the revised hypothetical emission values come from the Assessment of Studies document that these Keep It In the Ground organizations created. As described previously, the data supporting that analysis is fundamentally unsound for use in such a report, has not been quality controlled for accuracy, based on extrapolating short term data to annual emissions, and mathematically manipulated to generate emissions estimates to meet their Keep It In the Ground objectives.

2. *Cost of Regulations (Pages 11-12)*

The JEC regurgitates the ICF Study and the Waste Not study to allege that all methane regulations are cost effective. As shown above, while the aggregation of all regulations in the ICF study might be cost effective, individually, they are not. In particular, the OGI LDAR program described in the ICF Study raises significant cost effectiveness issues when realistic natural gas values are used and when the percentage of fugitive emissions at well sites are considered instead of all emissions that included permitted vents. These issues are more striking when they are viewed in the context of low production wells.

Similarly, the cost information in the Waste Not study is developed for a variety of requirements, most of which are separately addressed in Subpart OOOOa and are not a part of this reconsideration.

3. *New scientific evidence (Pages 85-88)*

The JEC castigates EPA for failing to use new information in its regulatory analysis. However, this new information is really analyses of existing information in a different format. At the heart of JEC Assessment of Studies that is referenced are data that suffer from a lack of onsite information, is taken for a short period of time, and is escalated to daily or annual emissions rate. These issues are repeatedly raised here because they pervade all of the JEC efforts to discredit the emissions factors used in the GHGI and to bolster the JEC arguments that far larger emissions are released.

A telling statement in the JEC submission demonstrates the nature of this report. It states:

> Notably, the Synthesis found that methane emissions from the production and gathering segments of the oil and natural gas supply chain were particularly underestimated in EPA's inventory. Furthermore, the Synthesis postulates that this underestimate is due to high-emission events at a subset of sites—precisely the abnormal operating conditions identified and remedied by frequent fugitive emissions monitoring.

The report "postulates" that its estimates are accurate. And, of course, its solution is the implementation of a costly OGI LDAR program. The Independent Producers could postulate that the higher emissions incidents are related to a short-term maintenance activity or a tank being filled, neither of which would be affected by an LDAR program. Since the Assessment of Studies chose not to work with producers during its data collection process, these issues cannot be confirmed.

4. *Low Production Wells (Pages 94-104)*

It is important to reiterate here what drives the JEC targeting of low production wells. These activists are committed to terminating production of American oil and natural gas. Their interest in low production wells reflects their commitment. They are not concerned with the new and modified sources of production that would be covered by Subpart OOOOa. These low production wells are largely small conventional wells drilled in reservoirs that have been producing for decades and have the potential to do so with low production wells. The JEC really wants to eliminate existing wells – the one million wells that would be captured through the implementation of Section 111(d) – particularly the 770,000 low production wells that cannot sustain the costs of the expensive OGI LDAR requirements of Subpart OOOOa.

The JEC present a number of claims regarding low production well decisions by EPA that demonstrate both creativity and duplicity.

The beginning part of this component of the JEC comments challenges EPA action to alter regulation of low production wells by referencing part of EPA's statement in 2016 removing its initial proposal to fully exclude low production wells. The full statement by EPA is included below with the JEC reference shown in italics:

> Based on the data from DrillingInfo, 30 percent of natural gas wells are low production wells, and 43 percent of all oil wells are low production wells. The EPA believes that *low production well sites have the same type of equipment (e.g., separators, storage vessels) and components (e.g., valves, flanges) as production well sites with production greater than 15 boe per day. Because we did not receive additional data on equipment or component counts for low production wells, we believe that a low production well model plant would have the same equipment and component counts as a non-low production well site.* This would indicate that the emissions from low production well sites could be similar to that of non-low production well sites. We also believe that this type of well may be developed for leasing purposes but is typically unmanned and not visited as often as other well sites that would allow fugitive emissions to go undetected. We did not receive data showing that low production well sites have lower GHG (principally as methane) or VOC emissions other than non-low production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites because the type of equipment and the well pressures are more than likely the same. In discussions with us, stakeholders indicated that well site fugitive emissions are not correlated with levels of production, but rather based on the number of pieces of equipment and components. Therefore, we believe that the fugitive emissions from low production and non-low production well sites are comparable.
>
> Based on these considerations and, in particular, the large number of low production wells and the similarities between well sites with production greater than 15 boe per day and low production well sites in terms of the components that

> could leak and the associated emissions, we are not exempting low production well sites from the fugitive emissions monitoring program.

What the selected quotation does not describe is that the referenced "stakeholders" were members of the JEC demanding that the Obama Administration regulate low production wells despite the absence of sound emissions data. These efforts were wrapped around the specious Super-Emitters study to give EPA some thread of a basis to cover low production wells. Now that EPA recognizes that low production wells are different, the JEC vents its outrage that the basis is inadequate.

The Independent Producers also recognize that EPA's effort to create a model low production well, while appropriate and appreciated, is a flawed effort but for different reasons. The Independent Producers believe that low production wells will emit less because of lower production, but in the current proposal the basis relies on component counts and that approach must be addressed. As stated previously, there is no simple way to create a model low production well facility and relying solely or primarily on the Fort Worth wells is not an adequate basis to base regulations. EPA recognizes that the Fort Worth wells do show differences but those differences are actually much larger than the Fort Worth wells suggest. The Fort Worth data includes too many facilities that are not likely low production wells and this creates a component count that is too high.

The Independent Producers have presented information addressing these issues in initial comments and elsewhere in this submission. Consequently, this portion of these comments will focus on the JEC statements in their comments.

The JEC jabbers about component count differences between the low and high production Fort Worth wells but misses the key points. As presented previously, the Independent Producers also question the EPA component count analysis from the Fort Worth low production wells because the wells appear to be far larger than most true low production wells. But, the critical aspect of EPA's analysis involves the components that drive the emissions estimates. Only two are significant.

The first is storage tanks. No one disputes that storage tanks can be sources of emissions. Tanks have vents to protect their integrity/safety. Tanks can also release emissions from open hatches or poor seals. The vent emissions are allowed; the hatch and seal emissions do not need an expensive OGI LDAR program to manage. Moreover, as shown in the Omara Marcellus 2016 data, these tank emissions are below the thresholds of regulation in the CTG.

The second key source is valve emissions. Here the emission factor used by EPA is questionable. The API reports on fugitive emissions programs established that the valve emissions factor was about 25 percent of the emissions factor used by EPA. Additionally, emissions from valves likely occur when the valve moves. For low production wells, valve movement is limited or nonexistent because the valves were designed for higher flows and as the well production declined, they essentially move to their maximum throughput position and stay there.

The JEC then complains that EPA's new assessment of information on low production wells is inadequate and concludes that it should not make a proposed change because its recent studies purport to show the low production well emissions are higher than EPA believes.

The JEC complaint raises a broader question. If the information currently available to EPA to define emissions from low production wells is inadequate, then the information EPA used to regulate low production well was also inadequate. Consequently, EPA's initial decision to regulate creates potentially severe economic and energy production results without a valid environmental justification – results that could become catastrophic for existing low production wells if regulated under Section 111(d).

The JEC attempts to paper over these realities by dragging out its array of reports. As described previously, these reports were not low production focused efforts, rely on data that is inadequate to make regulatory decisions and – when studied – show that they provide little useful information on the fugitive emissions from low production wells. If anything comes from them, it would be that tank emissions are sources – equipment that does not need an expensive OGI LDAR program to address if they even emit at a regulated amount.

5. *Fugitive Emissions Cost Analysis (pages 104-108)*

The JEC introduces a new fugitive emissions cost analysis to support its position that a semi-annual OGI LDAR program is sustainable for low production wells. There are numerous issues with the basis for this analysis. At the outset the analysis is based on the emissions estimations from the JEC that are speculative at best. Secondly, the analysis creates its own LDAR cost estimate. Interestingly, these costs appear to be about twice the annual costs of the ICF Study. Third, the analysis addresses only new wells that were subsequently shut-in. Fourth, the analysis is based on gross revenues rather than net revenue. In the material supporting the analysis, M.J. Bradley states:

> Newly drilled and modified wells get shut in when revenue falls below about \$150,000/year, regardless of what level of production is required to achieve this revenue target.

What is most compelling about this analysis is its inconsistency with other approaches.

For example, as described previously, the average price of natural gas has been \$2.22/mcf. Using this gross revenue number, the daily production number for a natural gas well to reach \$150,000 annually would be 185 mcfd. This would be about twice the threshold for a low production well of 90 mcfd and almost 8 times the average low production well nationally and 31 times the average Pennsylvania low production well. If the M.J. Bradley analysis was correct, no small well in Pennsylvania would be in operation.

Significantly, as the Independent Producers have discussed previously, gross revenues are not an appropriate approach to assess the validity of the cost effectiveness of regulations.

6. *EPA Estimate of Domestic Costs Fatally Flawed (Pages 126-130)*

The JEC challenges the EPA approach to its benefits analysis by criticizing its shift away from the social cost calculations EPA used in justifying its 2016 Subpart OOOOa regulations. This argument is bolstered in the JEC Supplemental Comments. However, as previously presented, analyses by organizations like NERA Economic Consultants have shown that social cost of methane determinations are highly questionable and can be manipulated to produce specific outcomes. For example, NERA concluded that a different look at the 2016 social cost of methane calculation would conclude that the regulation imposed net costs rather than benefits.

Response to AMEL State Equivalency Issues

1. *EPA's State Equivalency Determinations are Lawful and Meet the Requirements of Clean Air Act 111(h)*

In both the initial and supplemental comments submitted to the EPA by the JEC on December 17, 2018 and February 21, 2019 respectively, the JEC challenges the lawfulness of the state LDAR program equivalency determinations that EPA proposed in the Subpart OOOOa Reconsideration Rulemaking.[2] The Independent Producers disagree with these challenges and have outlined below support for the equivalency determinations and inclusion of the specific state LDAR programs as an alternative to compliance with the Subpart OOOOa LDAR program.

In the Reconsideration Rulemaking, EPA stated that "the 2016 NSPS Quad Oa allowed owners and operators to use the AMEL process to allow use of existing state or local programs" but EPA quickly realized the impracticality of this approach and further stated "it is possible that EPA would have over 300 identical applications from various owners and operators wanting to use the same state program at their affected facilities."[3] As the JEC points out in the summary table[4] of the 111(h)(3) approvals issued by EPA in their initial comments, dated December 17, 2018, these AMEL approvals were for an alternative work practice at a single large facility, such as an ethylene plant, a stark difference to the lengthy and onerous process that would be involved in approving individual AMELs for use at hundreds of upstream oil and gas well and tank battery facilities. As common sense would dictate, EPA sought "to streamline the process, ensure compliance, and reduce regulatory burdens, and continued its evaluation of state fugitive emission programs after promulgating the 2016 NSPS OOOOa". [5]

There are examples of EPA adopting state or local control requirements as alternative standards in other NSPS rules. For example, EPA incorporated, as an alternative standard into the Subpart Ja NSPS for petroleum refineries, the local requirements for flare minimization that were adopted by the Bay Area Air Quality Management District and the South Coast Air Quality Management District. In both of these cases, the Subpart Ja regulations establish the local flare minimization requirements "as an alternative to complying with the requirements" applicable to flares under Subpart Ja. [6] Following this general approach, EPA was reasonable in identifying the current state and local standards that achieve emission reductions that are equivalent to, or greater than, the reduction obligations imposed by EPA under the Subpart OOOOa regulations, and incorporate those equivalent standards as alternative standards to meeting federal performance standards.

---

[2] Reconsideration Rulemaking, 83 Fed. Reg. at 52080 (October 15, 2018)
[3] *Id.*
[4] JEC comments to Reconsideration Rulemaking December 17, 2018, page 46
[5] Reconsideration Rulemaking, 83 Fed. Reg. at 52080 (October 15, 2018)
[6] 40 C.F.R. § 60.103a(g). Specifically, section 60.103a(g) provides: An affected flare subject to this subpart located in the Bay Area Air Quality Management District (BAAQMD) may elect to comply with both BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. An affected flare subject to this subpart located in the South Coast Air Quality Management District (SCAQMD) may elect to comply with SCAQMD Rule 1118 as an alternative to complying with the requirements of paragraphs (a) through (e) of this section. The owner or operator of an affected flare must notify the Administrator that the flare is in compliance with BAAQMD Regulation 12, Rule 11 and BAAQMD Regulation 12, Rule 12 or SCAQMD Rule 1118. The owner or operator of an affected flare shall also submit the existing flare management plan to [EPA]." *Id.*

A. The fugitive emissions equivalency determinations do not have to be quantitative; rather, qualitative factors can be included in determining equivalency

In the Reconsideration Rulemaking, EPA conducted its evaluation by "compar[ing] the fugitive emission components covered by the state programs, monitoring instruments, leak or fugitive emissions definitions, monitoring frequencies, repair requirements and recordkeeping to the fugitive emission requirements proposed in this action." [7]

JEC's first attacked this evaluation process by stating that "EPA must conduct a quantitative analysis to approve an AMEL and may not average qualitative factors", and further stated, "equivalency determinations must be quantitative." [8] Clean Air Act 111(h)(3) does require that the AMEL will "achieve a reduction in emissions of any air pollutant at least equivalent to" the reduction under the NSPS.[9] However, the term "equivalent" is not defined in statute, nor is there a formula for calculating equivalence, especially for fugitive emissions at issue here where the leaks are not required to be quantified and the federal requirement is not to reduce a certain volume of fugitive emissions but rather, to simply find and fix the leaks.

Equivalence is however explained at length in the 2008 rulemaking where EPA deemed OGI technology equivalent to Method 21 for leak detection ("OGI AWP"). In the OGI AWP, EPA states, "The emission control effectiveness of any work practice is a function of both 1) its ability to detect leakage and 2) the frequency of monitoring. An equivalent work practice may require more frequent monitoring, depending on its mass rate threshold for detecting leaks."[10]

EPA further stated, "A more frequent monitoring requirement becomes necessary because higher mass emission reductions from large leaks, found earlier, are offset by some degree by smaller leaks which go undetected."[11] Based on this standard in the statute, larger leaks found earlier and more frequently should reasonably be able to offset smaller leaks that may not be found as timely.

This 2008 equivalency analysis clearly assessed qualitative factors (i.e. frequency) and determined that if a technology is less sensitive at detecting leaks then it could be deployed more frequently and this can be analogous to a different technology that may be more sensitive but is deployed less frequently.

In the Reconsideration Rulemaking, not only does EPA compare various qualitative factors in proposing to approve these state programs, EPA's evaluation process in the Reconsideration Rulemaking is almost identical to the evaluation EPA conducted previously in the OGI AWP as follows: "EPA believes that more frequent monitoring warrants allowance of a higher fugitive definition because larger fugitive emission will be found faster and repaired sooner, this reducing the overall length of the emission event." [12]

Therefore, qualitative factors should be assessed because the state programs are not identical to the federal programs but that does not mean they are less stringent in their ability to find and reduce fugitive emissions. There are many different combinations of monitoring instruments,

---

[7] Reconsideration Rulemaking, 83 Fed. Reg. at 52080 (October 15, 2018)
[8] JEC comments to Reconsideration Rulemaking, December 17, 2018, page 47
[9] 42 U.S.C. §7411(h)(3) (Clean Air Act Sec. 111(h)(3))
[10] Alternative Work Practice to Detect Leaks from Equipment Proposed Rule, 71 Fed. Reg. at 17404 (October 18, 2008)
[11] *Id.*
[12] Reconsideration Rulemaking, 83 Fed. Reg. at 52081 (October 15, 2018)

leak or fugitive emissions definitions, monitoring frequencies, repair requirements, etc… and these factors were all taken into consideration in crafting the state programs, many of which were included in a SIP for the air permit or program in which they have been incorporated, and SIPs must be approved by EPA. And again, fugitive emissions are not required to be quantified in Subpart OOOOa. Therefore, contrary to the JEC argument, these various program components *should be* compared "side by side" to determine the stringency or equivalence of the state program; this is the only feasible approach and is precedent based on the 2008 OGI AWP rulemaking. [13]

Last, in EDF's recent paper entitled *Pathways for Alternative Compliance, A Framework for Advance Innovation, Environmental Protection, and Prosperity,* referring to the approval process of emerging technologies as an AMEL to Subpart OOOOa's OGI requirement, EDF clearly states that non-quantifiable factors (i,e. frequency) must be taken into consideration to determine emissions reduction and therefore equivalency, as follows: "technologies with higher detection limits may yield greater or equivalent emission reductions than low detection limit technologies if used in a fashion that leads to quicker detection and mitigation of high emitting sources." [14] This is concurrent with EPA's point in the Reconsideration Rulemaking and directly contrary to the Environmental Commenter's statements on page 48 of their comments challenging EPA's inclusion of frequency as a factor to weigh in the equivalency determination.[15]

B. Taken as a whole, some state programs are more stringent than federal programs (e.g. Texas)

The JEC claims that "even for the sources that are subject to state programs, those programs vary in stringency and may not secure the same level of reductions as EPA standards."[16] Then the JEC does some type of analysis for four states and compare the percentage of emissions reduced under the state program to the emissions reduced under the federal program. For Texas specifically, this graph doesn't make sense and the footnote attempting to explain this data manipulation is nonsensical and confusing. [17]

Texas' LDAR program in the oil and gas Standard Permit is more stringent across the board, for each variable examined, as opposed to the Subpart OOOOa program. This Texas LDAR program requires the use of Method 21, with a leak detection of 500 ppm, as opposed to OGI allowed under Subpart OOOOa, the monitoring frequency is quarterly, and repairs must be made within 15 days.[18] And as the JEC point out, the frequency can eventually be reduced if less than 2% of leaks are found; therefore, it is impossible to calculate the emissions reductions this program will achieve in the future since that change in the frequency variable is unknown.

The state LDAR program AMEL option in Subpart OOOOa is relevant and useful where an operator is performing two concurrent LDAR programs at a site, and chooses to perform only the state program at the site in lieu of the federal program. This would only be done for the sites that

---

[13] [13] Alternative Work Practice to Detect Leaks from Equipment Proposed Rule, 71 Fed. Reg. at 17404 (October 18, 2008)

[14] *Pathways for Alternative Compliance, A Framework for Advance Innovation, Environmental Protection, and Prosperity;* EDF and Environmental Council of the States Shale Gas Caucus (April 2019)
[15] JEC comments to Reconsideration Rulemaking, December 17, 2018, page 48
[16] *Id.* at 50
[17] *Id.* at 51
[18] 30 TAC 116.620

are required to conduct both a state LDAR program required for the TX Standard Permit for example, and the Subpart OOOOa LDAR program. In Texas this would be for sites that have either a Standard Permit or Non-Rule Standard Permit. If the Texas program only covers a small percentage of sites (according to the JEC, it is only 5.5% of sites, and 12% of emissions)[19] then so be it. The point is that for those specific sites, the operator would not have a duplicative LDAR burden, with overlapping timeframes and two different onerous administrative requirements that would result in no added environmental benefit.

C. *State LDAR programs are included in state enforceable regulations and if promulgated through a State Implementation Plan (SIP), EPA retains oversight and enforcement authority over them*

The JEC also attacks the lawfulness of the inclusion of these certain state programs by stating that the programs were not deemed equivalent through the requisite notice and comment process of 111(h)(3).

State LDAR programs have already been subject to the notice and comment process for the state regulation and/or air permitting program they are included in. These LDAR programs may also be included in a SIP and therefore, were subject to comment during the SIP promulgation process *(the Texas LDAR program, for example, is included in the Standard Permit and Non-Rule Standard Permit and is included in the Texas SIP).* These are valid state regulatory programs and should be recognize as such. This approach is similar to EPA's handling of storage tanks in Subpart OOOO where EPA allowed tanks, if shown to be below 6 tpy in a state or local enforceable permit, to be exempted from Subpart OOOO's storage tank provisions. [20] Similar to tanks that are permitted below federal threshold limits, these state LDAR programs are enforceable by the requisite state agencies and should recognized as adequate, alternative programs under the premise of cooperative federalism.

Further, if these state LDAR programs were promulgated under a SIP, EPA has, and will continue to have, oversight and enforcement authority over these programs.

D. *Cooperative federalism should be recognized*

Under the well-established premise of cooperative federalism, EPA should recognize these programs in full, including the states' recordkeeping and reporting requirements. The states have recordkeeping and reporting to ensure compliance with their programs and EPA should give proper deference to states for compliance assurance for their state program. If the state program is not adequate in EPA's opinion, then EPA needs to address this issue with the states.

Complying with two different recordkeeping and reporting schemes on the same site(s) is an enormous administrative burden with no added environmental benefit. And requiring the federal reporting (which would require some Subpart OOOOa recordkeeping requirements to be met in order to comply with the federal reporting), and monitoring plan defeats the purpose and any benefit from EPA approving these state programs in the first place.

Cooperative federalism is a central tenet of the Clean Air Act. Over the course of its fifty year history, the Act has evolved first from a set of general principles intended to guide States as they undertook regulation of air pollution sources, to an extensive number of more targeted standards

---

[19] JEC comments to Reconsideration Rulemaking, December 17, 2018, page 51
[20] 40 CFR 60.5365

often prescribed by the federal government in the first instance and then implemented by the states. The principle that the States and the federal government will work in tandem to protect the nation's air resources is embodied throughout the Act. Congress, in section 101(a)(3) of the Act, declared air pollution control to be "the primary responsibility of States and local governments," 42 U.S.C. § 7401(a)(3), with the federal government providing "financial assistance and leadership," *id*. § 7401(a)(4).

For example, pursuant to section 110 of the CAA, while EPA develops the national ambient air quality standards, *see* 42 U.S.C. §§ 7408, 7409, states develop plans, called state implementation plans, to meet those standards. In that context, the U.S. Supreme Court has made clear that "[t]he Act gives the Agency no authority to question the wisdom of a State's choices of emission limitations if they are part of a plan which satisfies the standards." *Train v. Natural Res. Def. Council, Inc.*, 421 U.S. 60, 79 (1975). Similarly, under the CAA's visibility provisions, states have broad leeway to develop plans to combat regional haze that EPA cannot second-guess if the states have considered the statutory factors. *Am. Corn Growers Ass'n v. EPA*, 291 F.3d 1, 8 (D.C. Cir. 2002).

Section 111, the provision at issue here, fits squarely within the cooperative federalism tradition, with section 111(c) expressly calling on states to develop "a procedure for implementing and enforcing standards of performance for new sources" and calling on the Administrator to delegate "any authority he has … to implement and enforce such standards." 42 U.S.C. § 7411(c)(1). The Supreme Court has affirmed that these cooperative principles are the heart of the CAA again and again. *See, e.g.*, *Whitman v. Am. Trucking Ass'ns*, 531 U.S. 457, 470 (2001) ("It is to the States that the CAA assigns initial and primary responsibility for deciding what emissions reductions will be required from which sources."); *Union Elec. Co. v. EPA*, 427 U.S. 246, 269 (1976) ("Congress plainly left with the States, so long as the [NAAQS] were met, the power to determine which sources would be burdened by regulation and to what extent.").

State LDAR programs are precisely the sort of regulation over which states have special expertise, and they are proper subjects of state control.

Conclusion

The Independent Producers believe that these supplemental comments can better inform EPA as it makes the critical decisions related to the Reconsideration Rulemaking and would appreciate EPA's consideration of them.

The pending reconsideration gives EPA the opportunity to address regulatory actions that were rushed to a conclusion in 2016 without a full understanding of their consequences. Set forth herein, the Independent Producers reiterate and expand on key aspects of these actions – the treatment of low production wells, the importance of an LDAR program that can embrace new, cost effective technologies as they arise and the necessity of a coordinated federal and state regulatory structure to prevent unnecessary burdens on the regulated industry.

More explicitly, methane emissions from the natural gas and oil production sectors of the industry amount to about 1.2 percent of the GHGI and, as EPA is well aware, the Subpart OOOO regulations in place for facilities constructed after August 2011 are managing the major emissions from these operations. At issue here is the impact of some of the Subpart OOOOa regulations. These comments expand the Independent Producers concerns regarding the fugitive emissions requirements.

Specifically, the current Reconsideration Rulemaking proposal does not have a cost effective approach to the regulation of fugitive emissions from low production wells. Significantly, this issue is dramatically expanded because Subpart OOOOa is a methane based regulation that would result in the expansion of its scope from new sources to existing sources. As a result, instead of addressing 25,000 to 45,000 facilities per year, it would affect one million wells, 770,000 of which are low production wells. The regulations are not based on an adequate understanding of low production well emissions. They should not be applied as written. The Department of Energy (DOE) has initiated a study of low production well emissions that should be finished before low production well regulations are required and used to develop a sound low production well regulatory framework if one is necessary.

Similarly, the provisions regarding AMEL for emerging technology and state equivalency should be addressed to improve the ability of the regulated community to use better emerging technologies and to coordinate between federal and state requirements to avoid overregulation.

The Independent Producers appreciate the opportunity to submit these additional comments. If there are questions, please contact Lee Fuller (lfuller@ipaa.org or 202-857-4731) or James Elliott (jelliott@spilmanlaw.com or 202-361-8215).

Sincerely,

Lee O. Fuller

Lee O. Fuller
Executive Vice President
Independent Petroleum Association of America

APPENDIX D

INDEPENDENT PETROLEUM
ASSOCIATION OF AMERICA

June 3, 2020

VIA E-MAIL AND E-FILING

The Honorable Andrew Wheeler, Administrator
US Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

Re: Environmental Protection Agency's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Review at 84 Federal Register 50,244 (September 24, 2019) Docket ID No. EPA-HQ-OAR-2017-0757
And
Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources Reconsideration (October 29, 2018)
Docket ID No. EPA-HQ-OAR-2017-0483

Dear Administrator Wheeler:

The following Comments are submitted on the above-referenced proposed rule (Proposed Policy Rulemaking) on behalf of the following national and state trade associations: the Independent Petroleum Association of America (IPAA). IPAA has participated individually or through the Independent Producers in most, if not all, of the rulemakings and associated litigation since the Environmental Protection Agency (EPA or Agency) proposed to revise the New Source Performance Standards (NSPS) for the Oil and Natural Gas Sector in August 2011. 76 Fed. Reg. 52,738 (Aug. 23, 2011). [1]

IPAA represents the thousands of independent oil and natural gas producers and service companies across the United States. America's independent producers develop 91 percent of the nation's oil and natural gas wells. These companies account for 83 percent of America's oil production, 90 percent of its natural gas and natural gas liquids (NGL) production, and support over 4.5 million American jobs. A recent analysis has shown that independent producers are investing 150 percent of their U.S. cash flow back into American oil and natural gas development to enhance their already aggressive efforts to find and produce more energy.

These comments are filed in response to supplemental comments filed on April 13, 2020, by the Environmental Defense Fund (EDF) for itself and several other professional environmental issues advocacy organizations (EDF 2020 Comments). The EDF 2020 Comments address issues that arise in both the EPA 2018 Reconsideration proposal (EPA-HQ-OAR-2017-0483) and the

[1] IPAA incorporates by reference the Independent Producer Comments on the previous rulemakings associated with 40 C.F.R. Part 60, Subpart OOOO and Subpart OOOOa, including but not limited to the following documents: EPAHQ-OAR-2010-0505-4216, EPA-HQ-OAR-2010-0505-4626, EPA-HQ-OAR-2010-0505-4752, EPA-HQ-OAR2010-0505-4767, EPA-HQ-OAR-2010-0505-7001, EPA-HQ-OAR-2010-0505-7685, EPA-HQ-OAR-2010-0505- 12337, and EPA-HQ-OAR-2010-0505-12454.

EPA 2019 Proposed Policy rulemaking (EPA-HQ-OAR-2017-0757). Within the EDF 2020 Comments, there are specific issues related to comments provided by the IPAA. As the IPAA has shown in past comments, the EDF 2020 Comments continue to distort analyses of methane emissions as they seek to cripple American oil and natural gas production through the use of federal regulations that are not supported factually or legally justified.

Review of Major Issues

To put these supplemental comments in context, it is important to review the larger framework of debate and background on these issues.

1. Far too many accusations have been made regarding the scope and targets of the Subpart OOOO and Subpart OOOOa regulations. Industry does not dispute that it is appropriate to effectively regulate its emissions. For the production component of the oil and natural gas industry, volatile organic compounds (VOC) and methane are emitted together and the technology that controls either will control both. This is not disputed by EDF. For new sources, it makes no difference whether regulations apply to VOC or methane.
2. For most of the regulatory requirements under Subparts OOOO and OOOOa, the basic regulatory choices in the New Source Performance Standards (NSPS) meet the definition in the Clean Air Act for a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction (BSER) which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated. Many of these technologies – reduced emissions completions, low bleed pneumatic controllers, storage tank vapor recovery – have been used voluntarily by industry years before they were incorporated into the NSPS regulations. Industry's issues with these regulations have been largely related to interpretation and application in specific instances.
3. However, the fugitive emissions component of Subpart OOOOa presents a different circumstance. EPA's choice of its Optical Gas Imaging (OGI) based requirements resulted in locking a technology that is rapidly becoming obsolete. Newer technologies are presenting more cost-effective approaches to achieve EPA's objective but working these technologies into the framework of the NSPS presents an ongoing challenge.
4. The fugitive emissions regulations create an even greater problem regarding their application to low production wells (wells producing 15 BOE/day or less). When EPA was crafting its fugitive emissions program, it did not plan to apply it to low production wells. It never developed an accurate emissions profile or an economic assessment for low production wells. However, when EPA finalized the Subpart OOOOa regulations in 2016 under great political pressure from EDF and other professional environmental advocates, EPA expanded the scope of the requirements to all wells. The purported basis for the change in the final regulations, from the proposed regulations, was on data submitted by EDF during the Subpart OOOOa comment period. While it was apparently appropriate in 2016 to radically change course based on data supported during the comment period, EDF is singing a different tune when EPA is presented information during this comment period that they do not agree with and cannot legitimately refute. Significantly, EPA never revisited the implications of this change with regard its analysis of BSER, particularly with regard to the cost requirements for low production wells.

While the definition of low production wells is 15 b/day for oil and 90 mcfd for natural gas, the national average for low production wells is about 2.8 b/d and 20 mcfd, respectively. A regulatory structure based on high production wells in the hundreds of barrels per day and thousands of mcfd has a vastly different economic impact on low production wells typically operated by small businesses.

5. The EDF and professional environmental advocate driven decision to change the regulated emissions from the Subpart OOOO target of VOC to the Subpart OOOOa target of methane dramatically expands the implications of EPA's low production well decision – especially as to existing sources. Because methane is neither a criteria pollutant nor a hazardous air pollutant, making it the targeted emission triggers the potential use of Clean Air Act Section 111(d). Section 111(d) creates the authority to generate nationwide existing source regulations using the NSPS BSER technology for new sources. While EDF complains EPA's proposal to base regulations on VOCs and then remove the path to regulating existing source does not adequately evaluate the impact on the environment and public health, EPA's decision in 2016 to regulate methane never evaluated the economic impact of regulating existing sources under 111(d). It seems rather ironic that EDF is claiming that EPA is not adequately evaluating the impact of not regulating existing sources under 111(d) when EPA never adequately evaluated the impact of opening Pandora's Box on existing sources when it arbitrarily elected to regulate methane in addition to VOCs under 111(b). This little used Clean Air Act provision was intended to be a limited use section that would apply to a very small number of sources. EPA's prior use of 111(d) affected relatively few facilities. However, its application to the oil and natural gas production industry would cover approximately one million oil and natural gas wells with about 75 percent being low production wells.
6. Unlike other sections of the Clean Air Act, Section 111(d) uses new source requirements rather than existing source technologies such as the Reasonably Available Control Technology (RACT) of the Nonattainment provisions of the Act. EPA's Subpart OOOOa fugitive emissions program will not be cost effective for existing low production wells putting all of these wells that are already facing enormous economic challenges at risk. EPA never evaluated the impact on low production wells of regulating existing sources. As advocated by the IPAA, establishing a sub-category for low production wells would necessitate such evaluation and would help ensure such controls are cost-effective and justified.
7. EDF has shown throughout the entire deliberations over Subpart OOOO and OOOOa that its priority issue has been the application of nationwide regulations to existing oil and natural gas facilities with its primary purpose to eliminate these facilities. Throughout this period, as the IPAA has shown, EDF has demonstrated its persistent efforts to distort any data related to low production wells to achieve this objective.

Evaluating the EDF 2020 Comments

Much of the EDF 2020 Comments hinges on two components. One is a study from Alberta, Canada, "Repeated leak detection and repair surveys reduce methane emissions over scale of years", (Alberta Study). The other is EDF's Methane Policy Analyzer. Before addressing specific accusations in the EDF 2020 Comments, it is useful to review these items.

Alberta Study

The Alberta Study looked at 36 different facilities, 30 of which were well sites or production pads. Ultimately, in its analysis of emissions from production facilities, the report provides detailed information on 22 of these sites. EDF attempts to use the Alberta Study to bolster its recurring allegations that low production wells should be treated the same as high production wells with regard to the application of expensive OGI Leak Detection and Repair (LDAR) programs. However, a closer look at the Alberta Study reveals a different result.

First, while the Alberta Study does parrot the EDF line that low production wells should be regulated, its own data does not address low production wells. The production volume of the smallest well site that the Alberta Study presents is calculated to produce 1300 mcfd. This is over 13 times the regulatory definition of a low production well and over 50 times the average actual low production natural gas well.

Second, the compelling conclusion of the Alberta Study is its assessment that the dominant emissions sources at production operations are vessels – storage tanks. The Study states:

> If tanks do not contain a control equipment like a vapor recovery unit, tank-related emissions are classified as vents. Here, tank-related emissions contributed to 75% of all vented emissions, or 64% of total emissions.

This statement is telling at two levels. One, tank emissions dominate the site emissions overwhelming any leaks that would be found from process equipment. Two, the tanks do not have vapor recovery systems.

What the Alberta Study really says is that tank controls provide the larger benefit in any oil and natural gas production emissions management program. The 2012 Subpart OOOO NSPS required storage tank vapor recovery and these requirements have now been in place for roughly 8 years. Moreover, by identifying this reality, it supports the argument that the IPAA has made regarding the inappropriateness of the 2016 Subpart OOOOa NSPS LDAR requirements for low production wells. Given that the emissions from these wells are small and that storage tanks are the likely sources, the expensive OGI LDAR program is unnecessary. If a program is needed, one that would target storage tanks using methods to assure that thief hatches are closed and seals are maintained would effectively manage these small sources, particularly any existing facilities.

Methane Policy Analyzer

A second key element of the EDF 2020 Comments relates to its efforts to portray the magnitude of methane emissions. EDF presents an array of confusing emissions tables that it attributes to the application of its Methane Policy Analyzer. While the IPAA cannot address those tables with emissions outside oil and natural gas production, the EDF 2020 Comments present emissions estimates in Table 5 related to oil and natural gas production operations. IPAA has addressed this technique previously in earlier comments.[2] These comments were summarized in the Independent Producer comments to the EPA 2019 Proposed Policy rulemaking:[3]

---

[2] Independent Producer Response/Supplemental Comments filed June 17, 2019, to Docket ID No. EPA-HQ-OAR-2017-0483, pages 12-15.

[3] Independent Producer Comments filed November 25, 2019, to Docket ID No. EPA-HQ-OAR-2017-0757, pages 20-21.

Assessment of Studies: This EDF report was released with great fanfare during the 2018 World Gas Conference to create the appearance of new data showing methane emissions from the oil and natural gas industry value chain. The report purports to show that emissions are far higher than those reported in EPA GHGI. The JEC then refers to this report as a linchpin of its arguments for changes to the Subpart OOOOa proposal, particularly with regard to the fugitive emissions program with a special focus on low production wells. However, probing its details provides a far different perspective. Some highlights from the Independent Producers 2019 Comments follow:

> This report is not new data. Rather, it is a reconstruction of prior data from others' studies. For example, it regurgitates the same information in the Super-Emitters study and adds some additional material from others.
>
> As a consequence, the report suffers from no certainty regarding the quality of its data by possibly exacerbating bias and inaccuracies through incompatible sampling and data collection methodologies. It accepts as accurate everything it receives and these data have glaring deficiencies.

Additionally, the report is replete with questionable choices and use of data. It relies on short term measurements that it extrapolates to daily and annual emissions. It ignores that its own aerial survey data found no observed emissions from pneumatic controllers and equipment leaks that should have theoretically been high. It relies on the same specious percentage of sales approach as the Super-Emitters report. As the Independent Producers 2019 Comments conclude:

> All of these pieces point to a consistent conclusion regarding the validity of the Assessment of Studies report. It builds on data that is not consistent and then excludes data it does not want. But, the final aspect of its effort is telling. The key to the development of the Assessment of Studies is its statistical manipulation of its data to develop emissions values where it does not have data. Here are some important statements by the authors:
>
> > We assume our underlying emissions pdfs are lognormal, which is expected in a system where many independent random and multiplicative events can contribute to the occurrence and magnitude of emissions
>
> and
>
> > Results from both tests applied to all of the datasets used directly in this work indicate that one cannot reject the null hypothesis that the site-level sample data arise from a lognormal population distribution
>
> These are extremely weak arguments – "we assume … emissions pdfs are lognormal…."; "…one cannot reject the … hypothesis that

> the site-level … data arise from a lognormal population distribution."
>
> If they are not lognormal distributions, the entire framework for the Assessment of Studies report becomes suspect. Correspondingly, looking at the nature of the site emissions data – with all of the flaws associated with the assumptions in evaluating that data – there is little to suggest it is a lognormal distribution. These inadequacies and those described in the EID analysis of the report undermine the validity of the basis for arguing that the Assessment of Studies provides a basis for the fugitive emissions LDAR programs in Subpart OOOOa, particularly in their application to low production wells.

Collectively, the KIG lobby has used these reports to justify its targeting of low production wells. However, they do not make a plausible case. To the extent the KIG interests provide any viable data, it might indicate the most likely source of emissions is from storage tanks and not production equipment – however the volume of emissions is often below regulatory thresholds.

EDF's Methane Policy Analyzer is nothing more than a new name for an old, flawed product. Even though EDF can put together a table that purports to be accurate to a single digit, this calculation is meaningless. Its basis is purely derived from an array of distorted assumptions with the sole purpose of creating a regulatory scheme designed to drive existing low production wells out of business.

EDF's Comments in Context

The EDF 2020 Comments address a number of issues that pale (wilt?) under the light of scrutiny.

First, EDF spends a significant amount of effort highlighting action in Colorado to revise its LDAR requirements for oil and natural gas production facilities. There are two takeaways from these comments that are pertinent. One, Colorado was fully capable of developing its regulations without the need for the punitive nationwide existing source regulatory actions that EDF demands from the federal government. And, other states have developed their own regulatory systems as well. Two, it's unclear whether the Colorado regulations are the same as the NSPS requirements. However, it is apparent that EDF wants to imply that a semi-annual LDAR program for what are implicitly low production wells (storage tanks emitting 2 to 12 tons per year of VOC emissions) is cost effective. IPAA disagrees as described below:

> EDF reports that Colorado determined that cost of the program would be $742/ton for methane/ethane. This amount converts to about $190/mcf of methane.
>
> The average low production natural gas well in Colorado produces about 24 mcfd. The Alberta Study that EDF references in its comments projects a loss rate of about one percent of production for its lower production wells. This would be about 0.24 mcfd.
>
> Assuming that this loss could even be measured and all of it could be recovered (which no one projects as feasible), at a natural gas price of $2.00/mcf, it would result in income of 48 cents/day.

> To recover the cost of the LDAR program, it would require 400 mcf to be captured ($192/mcf ÷ $0.48). At 0.24 mcfd, it would take 1666 days.

Second, the EDF 2020 Comments relate a wandering collection of criticisms of the American Petroleum Institute's (API) assessments of the implications of an existing source regulation under Section 111(d) and throw a myriad of conflicting accusations into the record. IPAA will not try to respond to all of them but several allegations are pertinent to address. One of the major items relates to the number of wells that would be subject to a Section 111(d) regulation. This is an area that the IPAA has addressed several times but it remains important to revisit again. This issue revolves around the mix of existing wells at any given time. While the EDF 2020 Comments are intended to suggest that there is a need for an aggressive Section 111(d) LDAR program, IPAA believes that EDF has inadvertently demonstrated that such a regulation would fall on low production wells with high costs and limited effect.

On page 14 of the EDF 2020 Comments in footnote 53, EDF includes the following information:

> According to Enervus data, described *infra* n. 68, 82% of existing wells produce on average less than 15 barrel equivalents per day, based on the most recent 12 months of production.

This determination is largely consistent with the determinations of the IPAA that the principal impact of a Section 111(d) regulation would fall on low production, small business wells. But, it raises a question of what the universe of wells are that make up the remaining 18 percent of wells and what the emissions profiles of those wells would be. As pointed out earlier, the Alberta Study demonstrated that the predominant emissions at well sites come from uncontrolled storage tanks. Subpart OOOO imposed controls on storage tanks in 2012. The IPAA submitted the following information regarding wells drilled since Subpart OOOO was finalized in its comments on the EPA 2019 Proposed Policy rulemaking:[4]

> From 2012 through 2017, approximately 155,500 wells were drilled. However, several of these years were during low commodity prices that reduced drilling activity. Approximately, 41,000 wells are projected to be drilled in 2018 and 2019. Another 64,600 wells are projected from 2020 through 2022.

While the current economic stress on the oil and natural gas production industry will significantly reduce the number of wells drilled in the 2020-2022 timeframe, there are about 200,000 wells complying with Subpart OOOO. There are about 1,000,000 existing oil and natural gas wells in the United States and these Subpart OOOO wells exceed the 18 percent of the wells that the EDF 2020 Comments describe as being high production wells.

The importance of these facts is that the predominant emissions sources of large existing wells – storage tanks – are well regulated and would not be part of a Subpart OOOOa LDAR based Section 111(d) regulation, nor do they need to be. The issue then becomes whether there are real merits to compelling the 82 percent of existing wells that are low production wells averaging 2.8 barrels/day for oil and 20 mcfd for natural gas to comply with the Subpart OOOOa LDAR requirements. Returning to the Alberta Study, it showed that leaks from processing equipment were a minor share of emissions at well sites; for low production wells they would likely be unmeasurable. At the same time a storage tank based maintenance program could provide a path

[4] Independent Producer Comments filed November 25, 2019, to Docket ID No. EPA-HQ-OAR-2017-0757, page 10.

to manage those emissions. However, such a program is not the BSER technology that would be applied under a Section 111(d) regulation based on the 2016 Subpart OOOOa NSPS.

Third, the EDF 2020 Comments direct specific criticism toward the IPAA statements on low production wells. The Comments assert that the EDF Methane Policy Analyzer shows significant emissions from low production wells and that the Alberta Study supports regulations on low production wells. Each of these issues has been addressed above. However, to summarize our assessment of these allegations: (1) the EDF Methane Policy Analyzer is a contrived mechanism to generate emissions numbers based on a highly flawed manipulation of limited emissions data that has not been quality controlled, and (2) the Alberta Study concludes that the primary sources of well site emissions are storage tanks and its report did not include any low production wells.

Fourth, the EDF 2020 Comments allege the existence of health risks to those who live near oil and natural gas production facilities. This is a common Keep It in the Ground allegation. But, it is unsupportable. Routinely, these allegations are made in thinly contrived analyzes passed off as health studies. The Energy in Depth Health & Safety project regularly reviews and assesses these studies and others that evaluate them. Many are local reports, but some are more national in scope. Following are links to two reports that are illustrative, showing that oil and natural gas production operations do not present health threats from normal operations:

> Anti-Fracking Researcher Quietly Admits: Studies Show No Harmful Pollutants Near Oil And Gas Sites (https://eidhealth.org/anti-fracking-researcher-quietly-admits-studies-show-no-harmful-pollutants-near-oil-and-gas-sites/)
>
> Study Finds Model Used In Activists' Research Doesn't Jibe with Real Air Monitoring (https://www.energyindepth.org/study-finds-model-used-in-activists-research-doesnt-jibe-with-real-air-monitoring/?154)

Conclusion

The EDF 2020 Comments continue the perpetual effort to use the federal regulatory system as a mechanism to end the operation of hundreds of thousands for small business, low production wells through the application of requirements that were never designed for their emissions profile and economics. EPA should not fall into this trap. It has options available to it that can allow for the development of sound low production well emissions management. If it chooses to change the regulated emission to VOC, the management of emissions from new sources will remain the same since both VOC and methane are emitted together and managed simultaneously. Existing sources would be regulated through Control Techniques Guidelines based on RACT. EPA also has the option of crafting a subcategory within the NSPS program for low production wells that would allow EPA to develop appropriate requirements for low production wells that reflect their emissions profile and their economics.

IPAA appreciates the opportunity to submit these comments. If there are any questions, please contact Lee Fuller at lfuller@ipaa.org or by telephone at 202-857-4722.

Sincerely

Lee O. Fuller

Lee O. Fuller
Executive Vice President