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U.S. Environmental Protection Agency EPA Docket Center
ATTN: Docket ID No. EPA-HQ-OAR-2021-0295
Oil & Natural Gas Sector New Source Performance Standards
July 8, 2021

Greetings! On behalf of the nearly 3,500 members of the Kansas Independent Oil & Gas Association (KIOGA), I submit these comments to the United States Environmental Protection Agency (EPA) to address concerns related to methane emission compliance issues.

The oil and natural gas industry in Kansas supports over 118,000 jobs in Kansas, over $3 billion in family income, and over $1.4 billion in state and local tax revenue. The average Kansas oil well produces 2 barrels of per day and the average natural gas well produces 29 Mcf of natural gas per day. The small businesses that produce Kansas wells account for 92% of the oil and 63% of the natural gas produced in Kansas.

I am providing general comments about the regulatory environment in which the Kansas oil and gas industry operate and how that environment impacts small oil and gas exploration and production (E&P) businesses in Kansas. I am willing to provide additional details, upon request, related to any of the comments that have been submitted. The comments below are not intended to indicate that all federal regulations should be eliminated, or that Americans are better off without a regulatory framework for businesses to operate. The comments highlight several regulations that we believe should be reviewed and corrected. These areas have an impact on large companies in the oil and gas industry, but have a much greater impact on the small businesses within the same industry. I submit these comments to address opportunities for the oil and gas business segment in Kansas to work with regulators. Protecting the environment is in the best interest of our industry. Taking care of the environment is part of our goal as good corporate citizens. The owners and employees of Kansas oil and gas producing companies live in the same communities that they drill and operate oil and gas wells. They have a vested interest in not polluting the environment in which they and their families live.

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General Regulation Comments

On January 20, 2021, President Biden issued Executive Order 13990. Among other direction to the United States Environmental Protection Agency (EPA), the order instructs the EPA to consider taking two actions by September 2021 focused on reducing methane emissions from the oil and gas sector:

- Propose strengthening previously issued standards for new sources, and
- Propose emission guidelines for existing operations in the oil and gas sector.

These actions both fall under Section 111 of the Clean Air Act.

We (KIOGA) offer these comments as suggestions for meeting the methane emission goals and protecting the small businesses that are critical to the economies of Kansas and many other states around the nation.

EPA's decision to regulate methane in 2016 was a political decision driven by environmental activists and lobbying groups like the Environmental Defense Fund. These groups demanded methane regulation for a single purpose — to use a little utilized provision of the Clean Air Act (Section 111(d)) to regulate low production existing wells out of business.

Because 111(d) uses new source Best Systems of Emissions Reductions technology for existing sources instead of Reasonably Available Control Technology like other sections of the Act, these groups saw 111(d) as a pathway to require the cost ineffective Subpart OOOOa fugitive emissions requirements to push low production wells to shut down.

Understanding the scope of the issue is essential. Oil and natural gas production systems account for about 1.2% of the US Green House Gases Inventory (GHGI). Low production wells account for about 10-11% of U.S. production. Their emissions would be in the 0.10-0.20% range of the GHGI.

There are about 1,000,000 existing oil and natural gas wells. Approximately 150,000 of these wells have been regulated under Subpart OOOO and now OOOOa. That number grows each year. Of the remainder, 770,000 are low production wells.

Nationally, low production wells average about 2.5-2.7 barrels per day if they are oil wells and 22-24 mcfd if they are natural gas wells.

Subjecting these wells to the NSPS LDAR requirements puts them in severe economic jeopardy. Even EPA recognized this reality when it did not impose this LDAR program on low production wells in its October 2016 Control Techniques Guidelines (CTG) for existing oil and natural gas production facilities operating on Ozone Nonattainment areas.

Average Marginal Well Production		
State	Oil (b/d)	Natural Gas (mcfd)
Arkansas	3.95	34.76
Kansas	2	29
Louisiana	1.96	18.27
New Mexico	3.37	33.47
Oklahoma	2.66	29.23
Texas	2.99	28.86

EPA has never taken any significant data to identify the emissions profile of low production wells. It has relied on specious studies by environmentalists, used outdated studies from the mid-1990s that were never designed for regulations, and in its most recent Subpart OOOOa proposal relied on data from about 25 wells in one area, half of which do not appear to be low production wells. Only the U.S. Department of Energy (DOE) has initiated a study of emissions from low production wells. That study should be completed in 2021.

If any federal agency is creating regulations that have the capability of wiping out three-quarters of the facilities in an industry, it must have a full understanding of the industry and its regulatory actions. This has not been done.

Finding a Regulatory Pathway Based on Emission Data Where None Exists for Low Production Wells

Independent producers recognize the importance of environmentally sound regulations to manage industry emissions, including methane. KIOGA supports voluntary efforts by industry to reduce methane emissions. Our members are making constant improvements to the technology being used in the field to reduce, measure and report on emissions. Yet, more work needs to be done. KIOGA has met and will continue to work with the Biden Administration as it considers initiatives to reduce methane and other greenhouse gas emissions.

In January 2021, the International Energy Agency released a regulatory roadmap and toolkit focused on "Driving Down Methane Leaks from the Oil and Gas Industry." The roadmap details that, "understanding the nature and magnitude of your emissions will be critical to designing sound regulations." This is a primary tenet of what KIOGA seeks to convey with the Biden Administration. One key aspect of the independent component of the oil and natural gas production industry is its breadth – spanning from large, high production wells to low production wells. These wells do not all have the same emissions profiles, and those different profiles should be considered in regulations.

Low production wells are those that produce 15 barrels/day (or 90 mcfd) or less. The national average low production oil well is about 2.5 barrels/day and the low production natural gas well is about 24 mcfd. Of the roughly one million active oil and natural gas wells in the United States, about 750,000 are low production wells, typically operated by small businesses. The regulatory structure applied to low production wells is significant because their viability is so dependent on their cost of operation.

The 2016 Environmental Protection Agency (EPA) New Source Performance Standards (NSPS) fugitive emissions regulations created a specific problem for low production wells. When EPA developed its fugitive emissions requirements, it generated its Best System of Emissions Reductions (BSER) technology based on large, hydraulically fractured well sites and its initial proposal applied only to these sites. However, in finalizing the fugitive emissions regulations, EPA expanded their scope to include low production wells, but it never revised the BSER requirements to reflect this broader application. The high production well Leak Detection and Repair (LDAR) program is economically infeasible for low production wells and provides minimal environmental benefits. EPA agreed to reconsider the low production well impact of its fugitive emissions program. In its 2020 revisions to the NSPS, the fugitive emissions program now provided an off-ramp when well sites fall below 15 barrels/day. The implications for low production wells are further compounded by the decision to base the EPA regulatory program on managing methane. Under the Clean Air Act (CAA), the choice of regulating methane can trigger a nationwide existing facility regulation that would apply EPA BSER technology to the 750,000 low production wells currently in operation.

Industry does not question the need to cost effectively manage its emissions. Many independent producers participate in voluntary actions to reduce emissions — including fugitive emissions.

Industry seeks to find a regulatory pathway designed for the sources it regulates. The 2016 NSPS fugitive emissions program that was designed for large facilities should not be applied to low production well sites. The 2020 NSPS reconsideration moved to correct that error. EPA followed the path it used in its October 2016 Control Techniques Guidelines for low production wells when it excluded them from its model fugitive emissions program. There may be an appropriate low production well program. When EPA developed its NSPS regulations, it had no emissions profile for

low production wells. No extensive profile yet exists. The DOE initiated a study of low production well air emissions that should be completed by the end of 2021; it has been delayed by the COVID pandemic. **Preliminary results from the DOE third-party methane emission study of low production wells and facilities indicate no quantifiable or measurable emissions from wells or tank facilities**. If EPA needs to design a low production well program, it should utilize the emissions profile information now being developed by the DOE and then focus on the most cost effective options to address the key sources.

Background & Technical Information

Without its own information, EPA has been subjected to relying on external analyses. Many of these are developed by environmental activist lobbying groups to support their agenda. However, even these do not justify the NSPS fugitive emissions regulations for low production wells.

Environmental groups rely on a number of studies to make their arguments regarding the justification for controlling oil and natural gas production emissions. Several are described below with regard to low production wells.

Importantly, most of the emissions data collected at operating sites are done remotely without an understanding of the activities on the site, without knowledge of whether the emission was a fugitive release or a permitted release when a tank was being filled. Sampling was generally ten minutes to an hour, but the value would then be extrapolated to a daily rate and assumed to be constant for the year. While none of these studies were designed to address low production wells, almost all contained some low production well site information.

Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries (ICF Study) – Using the basis in this study, the potential recovery of methane would be 9 mcf/y for the national average low production well (24 mcfd). The gross and net cost effectiveness values would be $222.89/mcf and $221.22/mcf for the national wells. Natural gas currently sells for about $2.50/mcf at the well site.

Quantifying Cost-effectiveness of Systematic Leak Detection and Repair Programs Using Infrared Cameras (Carbon Limits) - For well sites and well batteries, the Carbon Limits study concludes that NSPS LDAR programs are not cost effective at 85% of these sites – a percentage that exceeds the share of natural gas production facilities that are low production wells.

Waste Not: Common Sense Ways to Reduce Methane Pollution from the Oil and Natural Gas Industry (Waste Not) - Its information is largely restatements of the information from the ICF and Carbon Limits reports. The only intriguing element of its recommendations is the realization that a fugitive emissions program needs to differentiate its requirements based on the production volumes of the facility.

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.

Aerial Surveys of Elevated Hydrocarbon Emissions from Oil and Gas Production Sites (Lyon 2016) – Of the 8220 well pads sampled, 4195 were low production wells, averaging 4.1 barrels of oil equivalent/day. Of these, 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. However, it does clearly call into question the benefits of the NSPS LDAR fugitive emission program to address the small percentage of low production wells that would be dealing with nontank emissions.

Methane Emissions from Conventional and Unconventional Natural Gas Production Sites in the Marcellus Shale Basin (Omara Marcellus 2016) - This report has 18 low production wells. The sampling 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). This is approximately 0.3% of the threshold for regulation under EPA's Control Techniques Guidelines for oil and natural gas production facilities.

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 the EPA Green House Gases Inventory. The environmentalists then refer to this report as a linchpin of its arguments for changes to the NSPS, particularly regarding the fugitive emissions program with a special focus on low production wells. However, the report hinges on assumptions that emissions form a classic statistical bell curve. If the emissions are not a bell curve, the entire framework for the Assessment of Studies report becomes suspect. Studies show that facility emissions are characterized by "fat tails" where a few pieces of equipment produce the emission and that most wells are low emitting as the graph below shows. Consequently, looking at the nature of the site emissions data, there is little to suggest it is a bell curve. These inadequacies and others undermine the validity of the basis for arguing that the Assessment of Studies provides a basis for the fugitive emissions LDAR programs in the NSPS, particularly in their application to low production wells.

Delving into the details of these reports demonstrates the importance of fully understanding the nature of oil and natural gas emissions. For low production wells, it creates a perspective that most emissions are more likely to come from storage vessels. Managing storage vessel emissions does not require a complex, expensive NSPS type of LDAR program.

As the EPA works to revise its regulation of methane emissions from the oil and natural gas industry, environmental activists have upped their game in spreading false information, often relying on misguided studies like those from the Environmental Defense Fund (EDF).

The EPA's proposed changes include ways to regulate "fugitive emissions" that escape from equipment and processes during oil and natural gas production.

As the rule's implications are debated, it's critical to consider important context around the industry's role in contributing to global methane emissions, how those emissions are estimated, the validity of studies like EDF's, and whether further regulations will actually impact emissions from today's technologically advanced and highly regulated oil and natural gas wells.

Here are four key issues to consider when discussing methane regulations.

1. Understanding the Scope of Methane Emissions and How They're Measured

Limiting methane emissions is no doubt an important piece of the overall greenhouse gas (GHG) emissions issue. But the fact is regulations targeting only the U.S. oil and natural gas industry can have little global impact, given the industry's relatively small contribution to worldwide emissions.

According to the **National Oceanic and Atmospheric Administration** and the **Global Carbon Project**, wetlands are the world's largest source of methane emissions. Natural sources make up 40% of all emissions. The remaining 60% are related to human activities including agriculture. ***Fossil fuel production and use account for 20% of global methane emissions.***

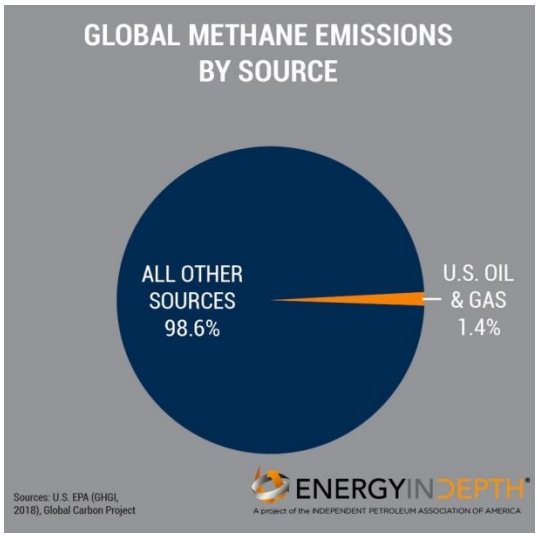
In the United States, that share is even smaller. The EPA's greenhouse gas reporting data show that the aggregate share of the inventory for oil and natural gas is about 3% and, importantly, the production share is just 1.22% of U.S. GHG emissions.

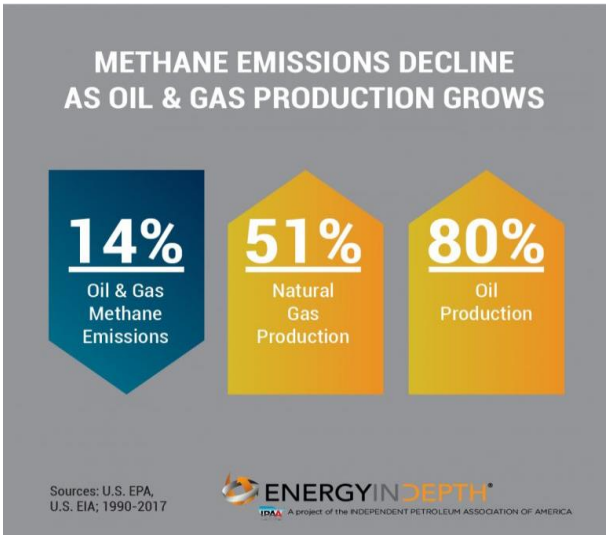
And that percentage is likely higher than the real figure, given the outdated factors used to estimate emissions from various equipment and components used in oil and natural gas production. It's quite an understatement to say technology and leak detection has improved since emission factors and estimated failure rates for equipment were developed in the 1990s.

As just one example of these improvements, the Environmental Partnership – a group of 66 top U.S. natural gas producers – recently noted that its participants had replaced, fixed or removed more than 31,000 high-bleed pneumatic controllers on their equipment. And 38 of the participating companies no longer use the devices, which are a notable source of leaks. Additionally, they found

that just 0.16% of surveyed equipment required repair, which raises significant doubts about the assumptions EPA uses to estimate equipment failure rates as a factor in emissions.

Such progress being shown by the industry to voluntarily reduce emissions highlights a clear piece of evidence that excessive regulations don't necessarily equal improved outcomes: U.S. methane emissions are falling even as production of both oil and natural gas are skyrocketing. Methane emissions from onshore U.S. oil and natural gas production fell 24%, while oil and natural gas production rose 65% and 19%, respectively, from 2011 to 2017, according to data from the EPA and the Energy Information Administration.





2. A 100-Year Timeframe is Crucial for Accurate Emissions Measurements

Because different greenhouse gases absorb heat at varying rates while remaining in the atmosphere for varying amounts of time, scientists and regulators developed a measurement tool called the global warming potential (GWP) to more accurately compare GHGs.

The standard timeframe used to calculate GWP is 100 years, according to the EPA and other agencies. Methane emitted today will last for about 10 years, and has a 100-year GWP of between 28 and 36.

In an attempt to overstate methane's role in warming the atmosphere, environmental interests have moved to calculating GWP on a 20-year timeframe, which as EPA states, "prioritizes gases with shorter lifetimes, because it does not consider impacts that happen more than 20 years after the emissions occur." Using that shorter timeframe, methane's GWP jumps to 84-87.

This inflated number better fits with the activist narrative in their push to claim natural gas has the same climate impact as coal. But using a 100-year timeframe generates a more accurate picture, given the long-term benefits of natural gas.

A brief published by the 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**."

3. Relying on EDF's Studies is Not a Sound Basis for Policy Decisions

A series of EDF-sponsored studies that over-estimated methane emissions from the industry have found their way into many discussions around EPA's methane rules. The studies' flaws, however, should exempt them from those discussions.

Notably, the EDF study that found methane leakage rates of 2.3% – 60% higher than the EPA's published rate of 1.4% was debunked last year (2018). In fact, **multiple other studies** have shown methane leakage rates to be between 1.1% and 1.65%.

The inflated number is very likely due to EDF's questionable methodology and poor data quality. The EDF study relied on remote sensing of emissions – and not the "bottom-up" onsite measurements that groups like the National Academy of Sciences recommend – which means it could not differentiate between fugitive losses and permitted emissions.

EDF also used data from other studies, which was collected before many in the industry had begun updating their operations with lower-emitting technologies – updates that actually preceded implementation EPA's 2012 rule that targeted methane as a "co-benefit." Using the data it had, EDF took the unusual step of ignoring any sites that had no measurements of emissions, and arranging the remaining sites into a bell curve that assumed a distribution of varying levels of emissions.

This is not good science, and should not serve as the basis for policy decisions that could impact small businesses all across the country.

4. The Majority of High-Producing Wells Are Already Regulated

On methane, there have been two major regulatory movements from the EPA over the past decade. The first occurred in 2012, which actually targeted emissions of volatile organic compounds (VOCs). Since the technologies available to capture VOCs also typically capture methane, the 2012 rule has colloquially been identified as EPA's first "methane rule."

The second push came in 2016, when the EPA formally targeted methane under what's known as Subpart OOOOa.

Because production from oil and gas wells declines over time – and rapidly in the early years – a look at the lifecycle and related production levels of the industry's well inventory will greatly inform the emissions discussion.

There are about one million oil and natural gas wells in operation around the United States, of which around 770,000 are classified as "low-producing wells." These wells produce, on average, 2.5 barrels of oil per day or 22-24 thousand cubic feet (mcf) of natural gas daily.

That means that more than 75% of the wells in America account for just 10% of U.S. oil production and 11% of natural gas. As low-producers, they account for an insignificant share of leaks or emissions.

Of the remaining 230,000 higher-producing wells, approximately 125,000 were completed from 2012 to 2017 under the requirements for new sources enacted in 2012 and another 20,000 to 30,000 were completed from 2018-2020. As noted above, many wells were completed by companies who voluntarily switched to lower-emitting technologies before EPA's 2012 rule was completed.

This essentially means that by the time any additional regulations are completed to cover existing sources of emissions, which is what the rule in question aimed to do, most if not all wells that are not low-producers will already be covered in some shape or form by EPA's 2012 rule.

This highlights the folly of attempts to bolt on additional regulations, and likely explains why activists wanted to use the 2016 update to target low-producing wells. Because such wells are economically vulnerable and more likely to be operated by small businesses, additional costly regulations would overwhelm their owners and eliminate their production.

The EPA realizes the important role natural gas plays in both powering the American economy and providing environmental benefits. Revising its methane rules will help strengthen both aspects in a more efficient way.

Compliance Cost and Project Economics Comments

Our experience is that EPA often underestimates the cost of compliance and overestimates the benefits provided by proposed regulations. As demonstrated in Table 1, the benefits increased more than the cost of compliance.

	Proposed Regulation	Final Regulation	% Change
2020 Tons of CH_4 Reduced	170,000-180,000	300,000	71%
2020 Tons of VOC Reduced	120,000	150,000	25%
2020 Tons ofHAP Reduced	310-400	1,900	535%
2025 Tons of CH4 Reduced	340,000-400,000	510,000	38%
2025 Tons of VOC Reduced	170,000-180,000	210,000	20%
2025 Tons ofHAP Reduced	1,900-2,500	3,900	77%
2020 CH_4 Climate Benefits ($ million)	200-210	360	76%
2025 CH_4 Climate Benefits ($ million)	460-550	690	37%
2020 Total CapEx ($ million)	170-180	250	43%
2025 Total CapEx ($ million)	280-330	360	18%
2020 Total Engineering ($ million)	180-200	390	105%
2025 Total Engineering ($ million)	370-500	640	47%
2020 BCF of CH_4 Recovered	8	16	100%
2025 BCF of CH_4 Recovered	16-19	27	54%

Table 1. EPA Proposed and Final OOOOa Compliance Cost and Benefits Estimates

We solicited quotes for 95% combustion devices to meet compliance with this regulation. Certified combustion devices are more expensive than devices that do not carry the certification, which is contrary to EPA's expectation that certified devices may be economically favorable. A certified combustion device that will meet gas flow rate requirements and gas quality will cost owners/operators $12,000 – $22,000 to purchase and an additional $8,000 to install, for a total installed cost of $20,000 – $30,000 per well. A conventional oil well may cost $300,000 to $600,000 to drill and complete. Installation of a combustion system could add 5% to 10% to the total cost of the project. The additional compliance cost will eliminate projects from being implemented.

If the cost of compliance for a subcategory 1 well (exploration or delineation wells) was only $405 (cited by EPA in the preamble of OOOOa), we would agree with EPA that the costs are not exorbitant; or "more than the industry can bear and survive". We are finding that compliance costs will be considerably greater than the estimates that have been provided. As noted above, installation of a certified combustor will cost $20,000 – $30,000. This cost does not include the cost to purchase and install a separator, install piping, complete the required surveys, and complete the required reporting for each well that is drilled. We estimate that the compliance costs could exceed 10% of the capital cost to drill a well. These costs are significant, and could drive many small operators out of business. We disagree with EPA's assessment that the industry can bear the cost and survive.

Over the past several years, many small oil and gas companies in Kansas have been working to develop compliance programs to meet the requirements of OOOOa. A sample of some of the compliance costs have been included in Table 2. This is not a complete list of costs, but an example of some of the additional activities that are required and the cost associated with each activity. As this list of costs demonstrates, the cost of compliance negatively impacts small business.

Activity	Cost	Frequency
VOC inspection of tank facility	$500 - $2,000	2x per year per facility/well
Documentation and record keeping	$20,000 - $100,000	Annually
Green Completion (only for non-delineation wells)	$10,000 - $15,000	Every new exploration well
Install sample fittings (parts and labor) for gas samples	$500 - $1,000	Every new facility
Laboratory analysis	$500 - $1,000	Every new facility
Engineering evaluation of lab data analysis	$250 - $500	Every new facility
PE Certification of combustion system	$2,500 - $3,000	Every new facility
Installation of combustion system	$20,000 - $40,000	Every new facility
Monthly inspection of combustion system	$250 - $500	Monthly
Monthly inspection after removal of combustion system	$2,500 - 4,000	Monthly
Design of combustion system	$10,000 - $15,000	One time cost
Develop record keeping system	$40,000 - $50,000	One time cost
Develop site specific monitoring plans	$30,000 - $50,000	One time cost
Purchase FLIR camera	$95,000 - $100,000	One time cost
FLIR camera training	$3,000 - $5,000	One time cost
Purchase sample collection equipment	$2,000 - $5,000	One time cost

Table 2. Compliance Activities and Costs Required by NSPS OOOOa

Many of the operators in the upstream oil and gas segment operated at a loss in 2020. A combination of crude oil demand destruction caused by the COVID-19 pandemic and a concurrent crude oil supply shock had a profound impact on the small businesses that make up the independent oil and gas industry in Kansas and across the nation. Owners/operators and their contractors cut capex by as much as 60% and cut operating costs by 30% or greater, and continue searching for areas to further reduce costs.

At a time when owners/operators are searching for ways to reduce operating costs to survive, EPA proposed methane regulation will likely measurably add to the cost of doing business. We believe that owners/operators will be required to employ additional staff for field surveys/maintenance activities and documentation burdens. We further expect that this regulation will result in a net loss in jobs from our industry because expenditures will be required for compliance activities, not new revenue generation. In an effort to reduce the cost of compliance, we recommend to reduce the documentation requirements (addressed in the Documentation section). The documentation burden continues to grow each year as new wells and tank facilities are added to the program through operating the business. We question the need for some of the data that EPA has required to be collected and reported.

We also recommend changing the requirements for emissions testing from using EPA Method 21 or a FLIR camera to permitting a soap bubble test. Each FLIR camera cost more than $90,000 and requires training to properly operate the equipment. Utilizing EPA Method 21 requires each operator to pay an outside contractor to visit each location with monitoring equipment and produce a report of leaking components. In addition, Method 21 also requires each facility to have a drawing of each fugitive gas emission component, and have each component tagged and labeled on the drawing. Both of these options are very expensive for small operators with limited budgets. Permitting the soap bubble test will provide existing staff a low cost way to identify leaks for repair.

Project Economics - EPA states that much of the methane and VOCs that are captured as a result of this regulation will be sold into the natural gas market. EPA is expecting owners and operators to use the gas sales to offset compliance costs.

Most of the gas that is not being sold today cost too much for owners and operators to collect, process, transport, and sell into the natural gas market. Management teams at energy companies have fiduciary responsibility to use owners' and investors' capital in the most efficient way possible. If projects to collect, process, and sell gas were economically attractive, companies would have already made the investment.

Many wells drilled and produced in Kansas have associated gas that needs to be purified to make it pipeline quality, which is a significant investment for a small volume of produced gas.

According to EIA, the Henry Hub contract price for natural gas is expected to average $2.93/Mcf in 2022. We performed Monte Carlo simulations around expected Kansas gas production, gas quality, compliance cost, operating cost, and product pricing. The outcome of our simulations shows that none of the scenarios are profitable (positive Net Present Value (NPV)) and any management team would reject the investment opportunity. Every well drilled will only have additional compliance costs added and no economic benefit will be realized.

This is another example where a Federal Agency issues a national level regulation without considering the impact across the country. EPA's "one size fits all" regulation format failed to consider local conditions. Projects in Kansas, and other areas around the United States will not realize an economic benefit for developing compliance programs.

Documentation Burden - We believe that EPA has underestimated the annual burden for recordkeeping and reporting requirements in NSPS subpart OOOOa. Information provided below shows that we are estimating our compliance cost to be significantly more than the estimates provided by EPA. Estimates provided are based on our understanding of how the regulation will impact our industry. The documentation required by this regulation creates ample opportunities for any operator to be cited by EPA for missing information.

In the final rule, EPA revised reporting estimated upward from the preliminary rule. In the preamble of the final rule, EPA states, "The estimated average annual burden (averaged over the first 3 years after the effective date of the standards) for the recordkeeping and reporting requirements in subpart OOOOa for the 2,554 owners and operators that are subject to the rule is 98,438 labor hours, with an annual average cost of $3,361,074. The annual public reporting and recordkeeping burden for this collection of information is estimated to average 20 hours per response. Respondents must monitor all specified criteria at each affected facility and maintain these records for 5 years."

Using the information provided above, EPA is estimating that the average owner or operator will spend approximately 38 hours per year (98,438 labor hours / 2,554 owners and operators), in the first three years, on compliance reporting activities. This time estimate is expected to cost the average owner $1,316 per year ($3,361,074per year / 2,554 owners and operators).

We estimate a one-time cost to develop a management and reporting system to be $40,000 - $50,000 and an ongoing cost of compliance of $20,000 - $100,000 per year (one-part time employee early in the program and potentially two full time people within a few years). These estimates are based on our understanding of the final rule, and only to meet the reporting requirements detailed in the regulation and discussed below. These estimates do not include the cost to achieve compliance with our equipment at the affected facilities.

With information provided below from the final regulation, we estimate that the required time and cost to complete the reporting required by this regulation is significantly greater than the estimates that EPA provided in the regulation, and cited above. The new regulation will have a substantial impact on our small businesses by measurably increasing our operating costs. This increase in operating costs will come from Leak Detection and Repair (LDAR) survey costs, reporting costs, and additional capital investment to meet emissions reductions. We do not believe that the costs incurred to meet compliance requirements will be offset through recovered product.

The required information will be a substantial burden on our small organizations to collect, manage, store, and report to the Agency on an annual basis. Small oil producing companies in Kansas continually search for ways to reduce operating cost and improve efficiency. As small operators, we must focus on low cost operations to be competitive with larger companies. We do not have the benefit of large scale operations to spread our fixed cost like large operators. Regulations such as OOOO and OOOOa, with significant requirements and little to no economic benefit threaten the viability of small operators in Kansas.

EPA states in the preamble, "Potential respondents under subpart OOOOa are owners or operators of new, modified or reconstructed oil and natural gas affected facilities as defined under the rule… The requirement in this action result in industry recording keeping and reporting burden associated with review of the requirements for all affected entities, gathering relevant information

performing initial performance tests and repeat performance tests if necessary, writing and submitting the notifications and reports, developing systems for the purpose of processing and maintaining information, and train personnel to be able to respond to the collection of information."

The documentation will necessitate many more hours than EPA's estimated 38 hours per year. Companies are evaluating the need to hire another one to two people solely to meet the reporting requirements of this new regulation. We believe that a full time position(s) may be required to meet all of the annual reporting and data management requirements to maintain compliance. We estimate that the fully loaded cost (salary and benefits) to fill this position will be an additional $50,000 – $60,000 per year per person to current operations. These requirements are not trivial.

Some operators in Kansas may drill 200 oil wells and perform work that would meet EPA's definition of a "modification" for more than 250 existing wells in a five-year period. This is an average of 90 wells being drilled or modified each year, not including associated tanks or other Fugitive Emissions Components. We expect this level of activity to resume as oil price increase for some of the active owners/operators in Kansas. We believe that smaller owners/operators will reduce their drilling and maintenance programs until the oil price increases again.

The reporting work will continue to grow each year as we continue to drill and modify wells because the current year work is added to all work from prior years. This growing work load will require the hiring of additional employees in the future.

The regulation states the following:

- "Owners or operators would be required to submit initial notifications and annual reports, and retain records to assist in documenting that they are complying with the provisions of the NSPS."
- "This notification would include contact information for the owner or operator, the American Petroleum Institute (API) well number, the latitude and longitude coordinates for each well, and the planned date of the beginning of flowback."
- "For well affected facilities, the information required in the annual report would include the location of the well, API well number, the date and time of the onset of flowback following hydraulic fracturing or refracturing, the date and time of each attempt to direct flowback to a separator, the date and time of each occurrence of returning to the initial flowback stage, and the date and time that the well was shut in and the flowback equipment was permanently disconnected or the startup of production, the duration of flowback, the duration of recovery to the flow line, duration of combustion, duration of venting, and specific reasons for venting in lieu of capture or combustion."

- "The rule includes new requirements for monitoring and repairing sources of fugitive emissions at well sites and compressor stations. The owner or operator would be required to keep one or more digital photographs of each affected well site or compressor station. The photograph must include the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file and must identify the affected facility."
- "The owner or operator would also be required to keep a log for each affected facility. The log must include the date monitoring surveys were performed, the technology used to perform the survey, the monitoring frequency required at the time of the survey, the number and types of equipment found to have fugitive emissions, the date or dates of first attempt to repair the source of fugitive emissions, the final repair of each source of fugitive emissions, any source of fugitive emissions found to be technically infeasible or unsafe to repair during unit operation and the date that source is scheduled to be repaired."
- "These digital photographs and logs must be available at the affected facility or the field office."

OOOOa also requires owners and operators to develop and maintain a corporate-wide and site specific monitoring plan. We have estimated costs as we continue to understand how this regulation will impact our organization. The estimates to develop a robust system will exceed 500 man hours to solicit input, develop the written program, review with the management team, and implement the program throughout our organization. At a fully loaded cost (salary and benefit) of $60 per hour, cost to develop this system is estimated at $30,000 - $50,000. We view the time invested in developing this type of system as part of the burden for recordkeeping and reporting.

As stated above, EPA requires digital photos and reports to be stored for up to five years. Development of a data management system, purchasing of additional data storage systems, and user training will require greater than 600 - 800 man hours. At a fully loaded cost (salary and benefit) of $60 per hour, the cost to develop an IT solution is estimated at $40,000 - $50,000.

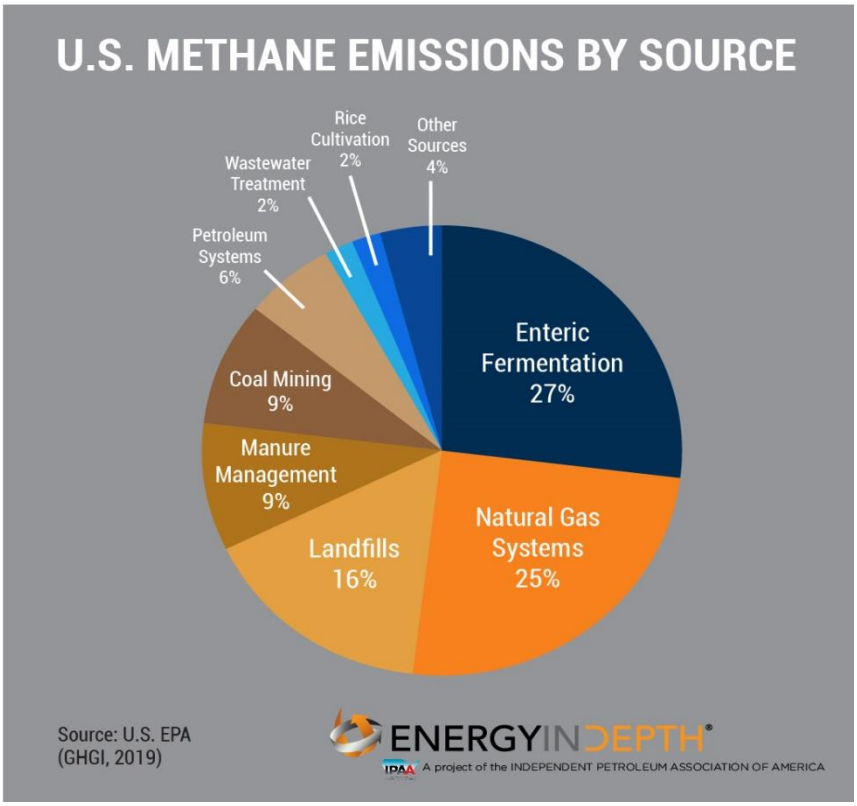
We question the value of some of the information that operators are required to collect. A sample of this is provided below:

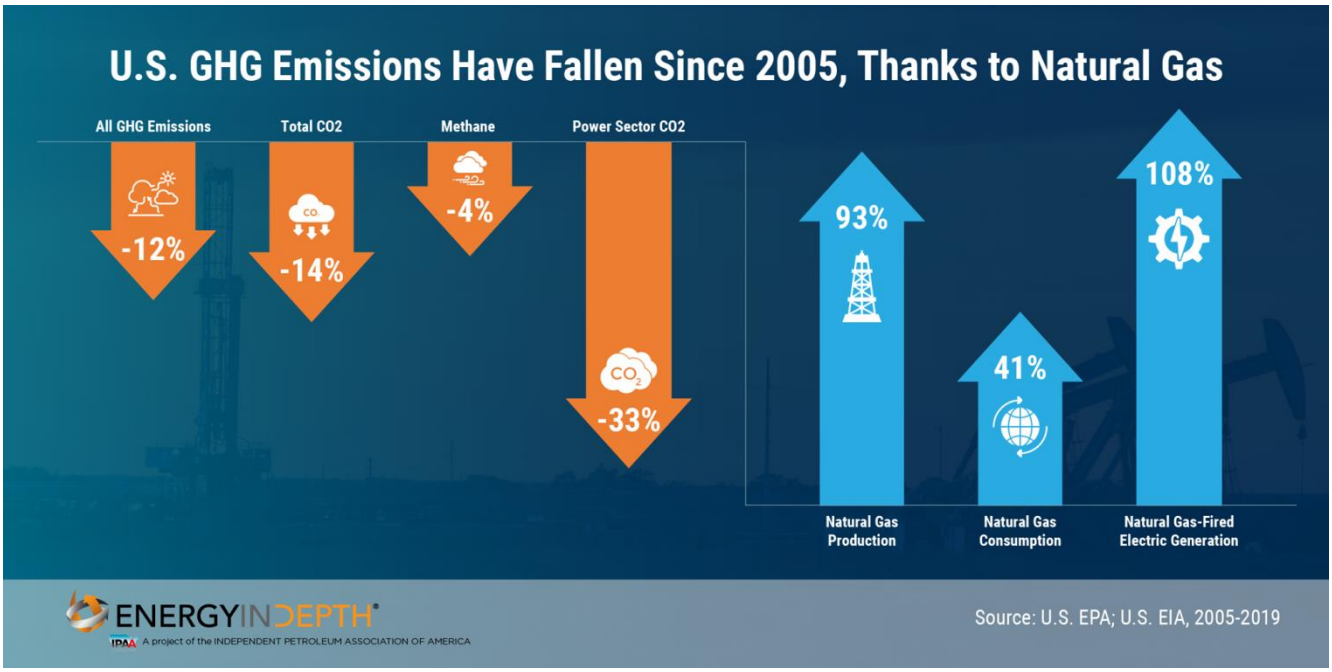
- EPA requires operators to submit notification to EPA no less than two days prior to hydraulic fracturing of an oil or gas well. We learned from a Kansas operator that they submitted the notification to EPA with "delivery" and "read" receipt notifications enabled for records. A year after the regulation was published, operators typically do not receive the "read receipt" for up to four weeks after the two-day notification has been submitted. What is the value in submitting notification to EPA two days prior to completing work if EPA is not going to read the email for four weeks? If EPA requires additional time to develop their programs and

implement systems, why were the operators only provided 60 days to develop and implement compliance programs?

- EPA is requiring 23 pieces of data to be collected from every LDAR survey that is completed. Every well that is drilled or modified and every associated tank facility must be inspected twice per year, with the following information collected in addition to photos and/or videos of the equipment at each location. Each piece of information must be logged into a database and stored for five years.
- EPA is requiring operators to retain records of the training that FLIR camera operators have obtained. One operator submitted an email to EPA requesting additional information about the required training to maintain compliance. EPA stated that there are no training requirements. If there are no requirements, why is EPA requesting operators to collect and maintain a log of operator training for every inspection completed for five years?
- Why does the operator need to collect the starting and ending time for each survey? This appears to be non-value added information to collect and maintain.
- EPA requires the maximum wind speed to be collected during every LDAR survey of an affected facility. EPA does not specify what wind speed is acceptable and unacceptable to complete an LDAR survey. If the operator is required to determine the maximum wind speed, why is this information collected and reported to EPA? This appears to be an area for operators to receive a violation because EPA did not clearly define expectations in the regulation. This requirement further increases the cost to complete LDAR surveys because additional monitoring equipment and time are required to document the wind speed.
- EPA requires a substantial amount of information to be reported about the potential to not monitor every fugitive emission component. We recommend eliminating all of the data that is requested related to a LDAR survey not being completed correctly and replace it with a general comments section for operators to provide information about why the survey was not completed. Logging deviations to the survey plan should not be a normal circumstance, but EPA is requiring documentation suggesting that incomplete surveys will be a normal occurrence. This is non-value added information that we are required to collect, that only adds time to our inspections and provides no benefit.

Emissions Data and Trends – According to EPA Greenhouse Gas (GHG) reporting data, oil and gas methane emissions account for only 1.22% of total U.S. GHG emissions. The U.S. decreased energy-related CO_2 emissions in 2019 by 140 million tonnes. That is more than any other country in 2019! Since 2005, U.S. greenhouse gas (GHG) emissions have fallen by 12%, total CO_2 emissions have fallen by 14%, methane emissions have fallen by 4%, and power sector CO_2 emissions have fallen 33%. Over the same period, natural gas production was up 93%, natural gas consumption was up 41%, and natural gas-fired electric generation was up 108%. The oil and gas industry has proven that over the long term, it is possible to lead in energy production <u>and</u> in environmental stewardship.


U.S. METHANE EMISSIONS BY SOURCE
Rice Cultivation 2%
Other Sources 4%
Wastewater Treatment 2%
Petroleum Systems 6%
Enteric Fermentation 27%
Coal Mining 9%
Manure Management 9%
Landfills 16%
Natural Gas Systems 25%
Source: U.S. EPA (GHGI, 2019)
ENERGYINDEPTH
A project of the INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA


U.S. GHG Emissions Have Fallen Since 2005, Thanks to Natural Gas
All GHG Emissions
-12%
Total CO2
-14%
Methane
-4%
Power Sector CO2
-33%
93%
Natural Gas Production
41%
Natural Gas Consumption
108%
Natural Gas-Fired Electric Generation
ENERGYINDEPTH
A project of the INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA
Source: U.S. EPA; U.S. EIA, 2005-2019

Hydraulic Fracture Definition - EPA finalized the GHG standards (in the form of limiting methane emissions) for well completions of hydraulically fractured (or refractured) gas wells as well as GHG and VOC standards for well completions of hydraulically fractured (or refractured) oil wells in OOOOa. Section 60.5430a provides the following definition of *Hydraulic fracturing*:

> **Hydraulic fracturing** means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions (P577).

We believe that the well completions performed in Kansas, and other similar areas, do not meet EPA's definition of Hydraulic fracturing for the geologic and engineering reasons provided below. We recommend that the definition in OOOOa be amended to explicitly exclude conventional wells from the regulation because the work performed does not meet the definition provided in the regulation.

Operations in Kansas do utilize pressurized fluids that contain water, proppant, and/or chemicals. However, the majority of the operations uses a process that neither penetrates tight formations like shale or coal, nor require high rate, extended flowback. Most Kansas operations result in little to no flowback from formations with higher quality reservoir properties than shale or coal. Ignoring those two facts discounts two thirds of the definition as outlined by Section 60.5430a. Enforcing this regulation based on "the process of directing pressurized fluids" alone; but not based on the type of formation or subsequent flowback directly ignores the criteria outlined by this regulation.

We infer that these two criteria were included in the definition of hydraulic fracturing, as pertaining to this regulation, to distinguish the varying completion styles of small, vertical, conventional drilling targets from large, horizontal, tight, unconventional drilling targets (such as shale and coal).

We assume that this distinction was developed due to the difference in potential greenhouse gas emissions from the dissimilar formation types and completion styles. While the amount of greenhouse gases emitted from each reservoir type has yet to be quantified, we assumed the greenhouse gas emissions will be proportional to the amount of hydrocarbons produced (i.e. the more oil and gas a well produces has the potential to produce greater amounts of greenhouse gases that well may emit). The average Estimated Ultimate Recovery (EUR) for vertical wells in Kansas is 20,000-30,000 bbl/well, where shale wells yield much higher EURs. Per EIA data, the average EUR is 168,000 bbl/well for an Eagleford shale well and 243,000 bbl/well for an Eastern Bakken well. Based on these numbers, a typical Kansas well will yield ~10% of the oil, and theoretically 10% of the greenhouse gas, of a typical oil shale well.

Table 7 is a comparison of typical reservoir and completion parameters for tight shale formations and for conventional formations targeted in Kansas. Many of the terms mentioned in the definition provided in Section 60.5430a are also included as a comparison between wells drilled in Kansas and by operators targeting tight, unconventional, shale formations.

Parameter	Kansas	Shale Formation
Well Orientation	Vertical	Horizontal
EUR	20,000 - 30,000 bbl.	150,000 - 250,000 bbl.
Permeability	0.01 - 0.5 Darcie	0.00000001 – 0.000001 Darcie
Flowback Time Period	Hours	Weeks – Months
Proppant Used	10,000 - 30,000 lbs.	300,000 - 4,000,000 lbs.
Water/Gas Injected	15,000 – 30,000 gal.	2,000,000 – 4,000,000 gal.
Stimulation Pressure	1,000 – 1,500 psig	5,000 – 15,000 psig

Table 7. Summary of Well Stimulation Properties

Geologic Review - The vast majority of reservoirs within Kansas produce from reservoirs that do not constitute tight formations, such as shale or coal formations, as defined within the standards of the EPA. The formations targeted are conventional reservoirs that are different from unconventional shales and coals for four main reasons:

1. Grain size – Reservoirs in Kansas are carbonates and sandstones rather than shale or coal. The Wentworth grain size classification categorizes sands as being larger than 0.0625mm while clays (main component of shale) are categorized as grains smaller than 0.0039mm, more than ten times smaller than the finest-grain, conventional reservoir in Kansas. Furthermore, coal is not composed of consolidated grains, but rather consolidated, thermally mature organic matter.

2. Organic content – The shales and coals exploited outside of Kansas are targeted due to their organic content. Coal is composed of nearly 100% total organic content (TOC) whereas productive shales are typically greater than 2% TOC. Many of the major producing shales have much higher TOCs, some exceeding 10%. The conventional reservoirs in Kansas have only trace amounts of TOC at best. The TOC content is very important in shale and coal because the hydrocarbons being targeted are located within the porosity of the organic matter. Producing the hydrocarbons from the organic matter requires large hydraulic fracturing stimulation.

3. Permeability – In Kansas reservoirs permeability in locations is generally measured in millidarcies, and some are measured in Darcies; while in shale reservoirs, permeability is measured in nanodarcies. The difference between a millidarcy and a nanodarcy is six orders of magnitude (10-3 vs. 10-9 Darcies, respectively). Because the permeability and nature of the formation types vary so much, the two reservoir types require two different analytical methods in order to measure rock properties.

4. Producability – The finer grain size, nanoscale organic porosity, and low permeability of shale and coal require extended reach laterals with extensive fracturing to increase permeability over large drainage areas to achieve economical flow rates. Reservoir fluid flow typically does not occur outside of the stimulated rock volume. The larger grain size and higher permeability of the conventional reservoirs of Kansas require much less stimulation, and typically a much smaller drainage area, to achieve economical flow rates. Reservoir fluid flow will occur outside of the stimulated rock volume in the more permeable Kansas reservoirs.

Engineering Review - 99% of the oil produced in Kansas comes from sandstone and carbonate formations that have permeabilities up to six orders of magnitude times greater than that of average shale and coal formations. This greater permeability in the producing formations in Kansas do not lead to high rate, extended flowback periods following well completions. The average time from completion to being put on pump for production is less than 48 hours, with a majority of that time spent installing the production equipment.

A summary of EPA's response states that EPA considers our flowback to be "high rate" and "extended". An examination of the engineering and geologic data provided above shows that the high volume hydraulic fracture work that is completed on unconventional oil and gas wells are magnitudes greater than the hydraulic fracture work that is generally performed on conventional wells. The potential for VOC and GHG emissions from an unconventional oil or gas well will proportionately be higher than conventional oil or gas wells.

EPA also stated in their response that the NSPS was intended for all oil and gas extraction, and that a well-by-well or formation-by-formation basis under the provided definition was inconsistent with EPA's express intent to address GHG and VOC emissions from all hydraulically fractured oil well completions. This is another case where EPA's attempt to develop a national regulation to cover all oil and gas operations did not consider the differences between large and small operators, or conventional and unconventional wells. Additional information is available upon request.

NSPS OOOO Exemptions - EPA provided an exemption for low volume wells in the proposed OOOOa regulation, but removed it in the final regulation. The oil and gas industry supports this exemption being returned to the regulation as emissions from low volume wells are small compared to large volume wells that are much higher in pressure.

Removal from Monitoring - EPA did not provide a way to remove a well head or tank battery from the monitoring program once the facility met EPA's threshold for monitoring. NSPS OOOO provided methods to remove tank facilities from the program. We recommend a common sense mechanism be added to the regulation to remove wells from the monitoring program when no benefit exists for continual monitoring. This provision will be important for small businesses to continue to reduce operating costs. Many low volume wells do not produce a measurable amount of gas, but will continue to be inspected because EPA did not provide a method to remove them from the program.

Tank Emissions Monitoring - EPA provided a mechanism to remove a combustion system from a tank facility under OOOO when the emissions falls below four tons per year for 12 consecutive months. EPA requires operators to test the emissions on a monthly basis, in perpetuity to prove that the emissions remain below four tons per year.

Each emissions test requires someone from field staff to spend approximately four hours at each tank facility to conduct the emissions testing. This testing requirement will be a significant burden on field staff as combustion systems are removed from the tank facilities. Eventually, operators will need to employ one person to do nothing but test emissions from tank facilities where combustion systems have been removed.

EPA may believe that combustion systems can operate on a tank facility for the life of the tank facility. Unfortunately, the VOC and GHG flow rate declines at a similar rate as the reservoir that the oil is being produced. Eventually the tank facility does not produce a sufficient volume of gas to sustain combustion and supplemental propane must be burned to meet EPA's requirements. At this point, more GHG is produced through the propane combustion than is emitted from the tank facility.

As oil is produced from a reservoir, the gas to oil ratio decreases with time, just as the reservoir pressure decreases with time. The probability that VOC or GHG emissions will increase from a tank facility without modification to one of the wells is very small.

We recommend that the tank facility be tested quarterly for the first year after the combustion system has been removed from the facility to prove that emissions did not increase. After the first year of production without the emissions control equipment in place and no increase in emissions, the subsequent monitoring is eliminated. At this point, emissions have been below four tons per year for two consecutive years.

Conclusion and Recommendation

To be clear, the small independent oil and natural gas producers in Kansas and across the nation recognize the need to manage their air emissions. The issue for these small businesses has never been whether regulations were necessary; it has always been whether the regulations were sound and cost effective.

When the EPA proposed its fugitive emissions program in 2015, it did not include low production wells – wells that produced less than 15 barrels per day of oil or 90 mcfd of natural gas. When EPA finalized the regulations, it expanded the scope to include low production wells under pressure from environmentalists. However, the EPA never revised the LDAR technology requirements to reflect this expansion. This is significant because the cost effectiveness of an LDAR program is very different for large, hydraulically fractured well sites compared to small business low production wells. And, it is an even larger issue when the regulated emission is methane which triggers a nationwide existing source requirement where the brunt of the impact falls on the 750,000 low production wells that average about 2.5 barrels/day and 25 mcfd.

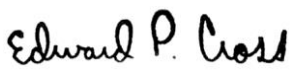
As EPA looks at this rule, it is critical to consider important context around the small independent oil and gas producer's contribution to methane emissions. We urge the EPA to allow ample time to consider the US DOE third-party study of methane emissions from marginal wells and tank facilities. Preliminary results from the DOE study show no quantifiable or measurable emissions from marginal wells or tank facilities. The DOE study was originally scheduled to be released in 2020 but was delayed due to COVID-19 restrictions. The DOE has indicated they plan to release the final study by the end of 2021. We think the final DOE study will confirm that there are no quantifiable or measurable methane emissions from marginal wells and tank facilities.

Finally, we urge the EPA to consider the information provided herein and use it to justify excluding wells that fall below 15 barrels/day of oil production and 90 mcfd of natural gas production from the burdensome fugitive emissions program.

Contact Information

For further information or any questions, please contact Edward Cross, President, Kansas Independent Oil & Gas Association, 800 SW Jackson Street, Suite 1400, Topeka, Kansas 66612 (785-232-7772; email ed@kioga.org).

Sincerely,



Edward P. Cross, President
Kansas Independent Oil & Gas Association