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U.S. Environmental Protection Agency EPA Docket Center
ATTN: Docket ID No. EPA-HQ-OAR-2021-0317
Proposed Rulemaking for *Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil & Natural Gas Sector Climate Review*
January 28, 2022

Greetings! On behalf of the nearly 3,000 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 100,000 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 25 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.

The following comments are offered to address issues of significant concern for the small businesses that make up the Kansas independent oil and gas industry. I am willing to provide additional details, upon request, related to any of the comments that have been submitted. The comments highlight several issues with the proposed rulemaking 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 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.

In addition, in the cost benefit analysis, the EPA uses an interim Social Cost of Carbon (SCC) value of $51 per ton. The $51 per ton SCC includes global climate change impacts that are outside the jurisdiction of the EPA. We believe the EPA should use the most recent SCC of $7 per ton that was limited to climate change impacts within the United States.

We also find it disconcerting that the EPA references conflicting global warming (GWP) potentials for methane (80, 30, 29.8, 27.2, and 25) throughout the proposal instead of using the established GWP used for emissions inventory purposes.

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

The small businesses that make up the independent oil and natural gas industry 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. KIOGA 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. The U.S. Department of Energy (DOE) initiated a study of low production well air emissions that was completed at the end of 2021. **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 developed by the DOE and then focus on the most cost effective options to address the key sources.

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 and 2021. 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 $3.79/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.

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.

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.

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.

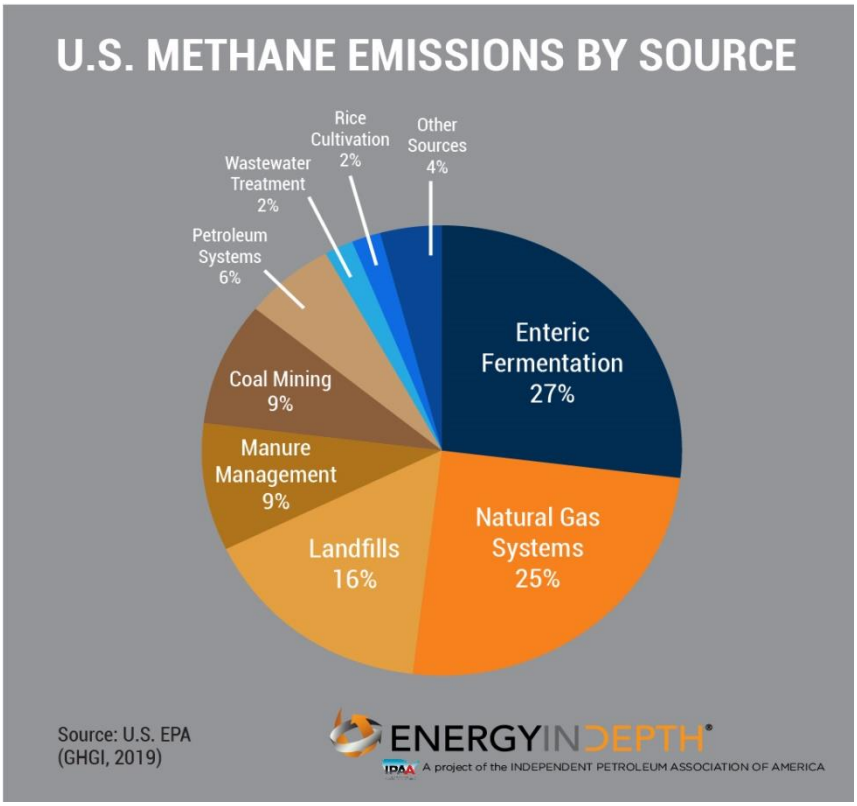
Some operators in Kansas may drill 200 oil wells and perform work that would meet EPA's definition of a "modification" for more than 250 existing wells in a five-year period. This is an average of 90 wells being drilled or modified each year, not including associated tanks or other Fugitive Emissions 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.

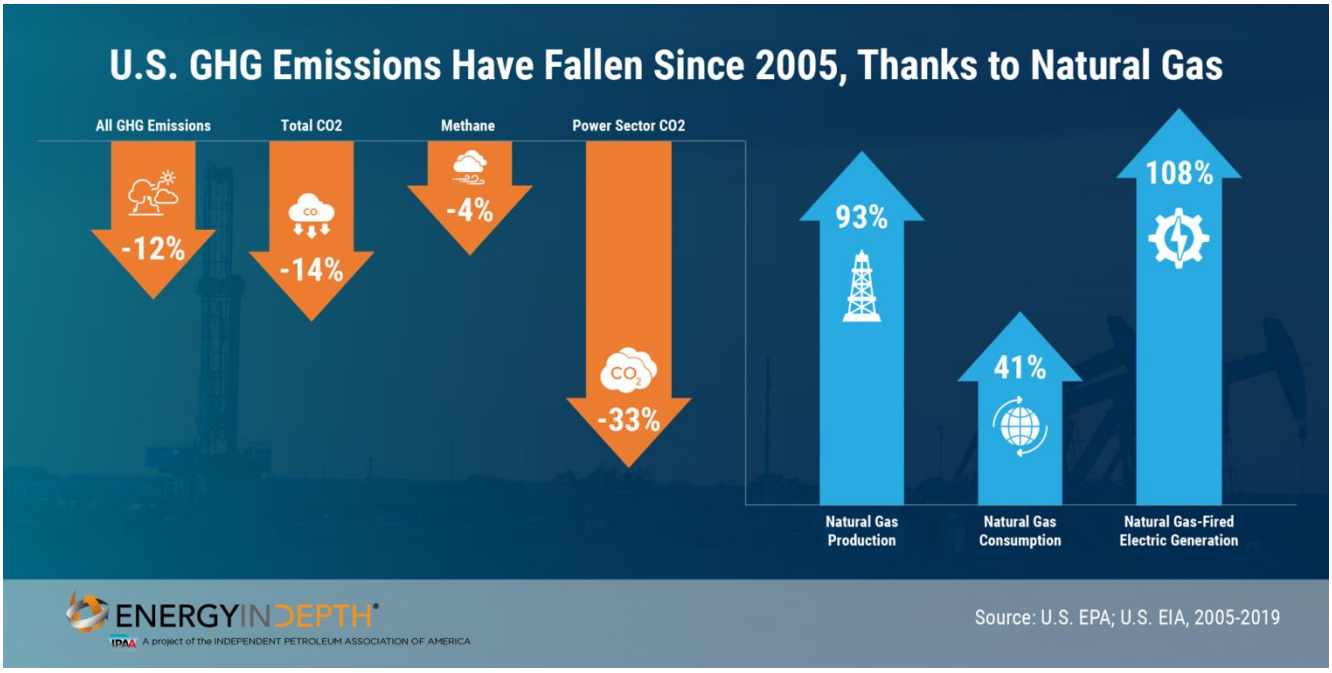
The reporting work will continue to grow each year as we continue to drill and modify wells because the current year work is added to all work from prior years. This growing work load will require the hiring of additional employees in the future.

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 industry. 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.

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.





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 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.

Impact of Emission Guidelines on Kansas

The proposed emission guidelines (EG) most certainly would impose a burden and insurmountable costs for the small businesses that make up the independent oil and gas industry and for the state of Kansas. There are over 62,000 oil wells and over 20,000 natural gas wells in Kansas.

Other comparable states estimated costs to develop and implement this proposed rulemaking to be over $40 million annually. Furthermore, these states estimate the cost on the proposed timing (final compliance within 2 years) is even more outrageous at over $278 million annually. The estimate includes 2,708 additional full time equivalent persons to be hired. Kansas would incur similar costs.

KIOGA is deeply concerned about the small businesses that make up the independent oil and gas industry in Kansas. It is not acceptable for these entities to be subject to this proposed federal regulation for existing sources and they should be exempted from applicability.

Many of the small businesses that make up the Kansas oil and gas industry do not have the knowledge required to perform a fugitive emissions survey or to perform air emissions calculations for a well that has existed for multiple generations. These entities should not be burdened with having to figure out how to do so or burdened with hiring, and paying for, an environmental consultant to perform the survey and calculations on their behalf.

Emission Guidelines (Subpart OOOOc) – The EPA did not provide any regulatory text, therefore, the ability to provide comments is limited.

KIOGA supports the exclusion of "wellhead only well sites" from the EGs for existing sources and concurs that the benefits would not be worth the costs. The EPA needs to include a definition for wellhead only well sites and low production wells in the yet to be proposed regulatory text.

KIOGA does not support the proposal that "wellhead only sites" must calculate fugitive emissions. The EPA stated it does not believe these emissions would exceed 3 tons per year (tpy) threshold to require routine monitoring; therefore, it should not impose substantial requirements. Additional, the small businesses that make up the independent oil and gas industry should not be burdened with purchasing and learning how to operate an optical gas imaging (OGI) device costing approximately $90,000 to comply with the fugitive emissions requirements at wellhed only sites. The EPA did not evaluate the cost for these small entities to comply with the proposed EGs; therefore, they should be excluded from applicability.

Fugitive Emissions – KIOGA opposes the proposed baseline requirements for fugitive emissions at well sites with fugitive emissions between zero and three tons per year. This action would impose significant burdens and costs without providing any air quality benefit.

In the final EGs, low production wells should be exempt from the rule along with small businesses. The designated facility category for fugitive emissions at well sites between zero and three tons per year should be eliminated in the final rule because low production wells should be exempt.

KIOGA objects to the proposal to repeal the amendments in the 2020 Technical Rule that exempted low production well sites from monitoring fugitive emissions under the NSPS (86 Fed. Reg. 63118).

Liquids Unloading Events – KIOGA urges the EPA to reconsider its determination that each liquids unloading event represents a modification, making the well subject to new source standards for purposes of liquids unloading standards. Oil and natural gas wells produce the largest volume at the time they are initially drilled; followed by a declining curve over time. Depending on when the liquid unloading event occurs, the production would only return to where it should have been on the declining production curve assuming the liquid unloading event was successful. The production never increases to the volume the wells observed early in the production curve for a new well. Liquid unloading events are considered normal operation for well operators.

Community Monitoring Program - The EPA's desire to implement a community monitoring program to detect large emission events is troubling. To be clear, this regulatory approach should be abandoned; however, if the EPA is insistent on pursuing this course of action, it is vital that the program be carefully crafted to ensure protections from overzealous activists seeking to induce financial hardship on producers with false reports. The proposed rule states that the EPA "generally envision[s] a program for finding large emission events that consists of a requirement that, if emissions are detected above a defined threshold by a community, a Federal or State agency, or any other third party, the owner or operator would be required to investigate the event, do a root cause analysis, and take appropriate action to mitigate the emissions, and maintain records and report on such events." If the EPA intends to force expensive compliance costs on producers based on the analysis of "any other third party", it is vital to set very high standards for what constitutes credible data. There must be training requirements for submitting parties, and producers need to be given adequate time to complete any required compliance actions after notification.

Questions

1. For affected existing sources constructed on or before November 15, 2021, that will be affected facilities under the EGs of 40CFR60, Subpart OOOOc, will they continue to also be subject to the NSPS of 40CFR60, Subparts OOOO or OOOOa, as applicable?
2. Will designated existing facilities under 40CFR60, Subpart OOOOc (EGs) continue to be subject to 40CFR60, Subpart KKK? Please clarify if both the 40CFR60, Subpart KKK VOC standards will apply and the 40CFR60 Subpart OOOOc (EGs) presumptively approvable methane standards will apply to these facilities, or if 40CFR60, Subpart KKK will no longer apply, and these sources will be regulated by States under 40CFR60, Subpart OOOOc. If the sources will be subject to regulation under both subparts, has the EPA reviewed these subparts such that the sources will not be subject to conflicting requirements and that the requirements are streamlines?
3. Please clarify how to calculate the emission factors to determine the level of methane emissions for leak monitoring frequency and to determine the GHG standards for well sites shown in Table 3 at 86 Fed. Reg. 63121. The EPA has stated that the GHG emission factors in 40CFR98, Subpart W were to be used and not the emission factors in EPA-453/R-95-017
4. Are the proposed GHG standards for 95% methane reduction for storage tanks with PTE > 20 tpy shown in table 3 at 86 Fed. Reg. 63121 more stringent than the current 6 tpy VOC threshold for tank emission reductions?
5. Is the 2 scfm threshold for reciprocating compressors identified in Table 3 at 86 Fed. Reg. 63121 determined on a per cylinder basis or on a per compressor basis? Some compressors have a common vent, which would require piping modifications if required to measure the vent rate from each cylinder.

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. Results from the DOE study show no quantifiable or measurable emissions from marginal wells or 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

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