Appendix B: Written Comments Submitted by Small Entity Representatives

Appendix B1. Written Comments from potential SERs following the June 29, 2021 Pre-Panel Outreach Meeting

July 13, 2021

Lanelle Wiggins, RFA/SBREFA Team Leader
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Delivered via: Wiggins.Lanelle@epa.gov

Ms. Wiggins:

Thank you for the opportunity to provide written comments to the “Pre-Panel Outreach Meeting” conducted by EPA on the rulemaking, “Oil and Natural Gas Sector New Source Performance Standards,” on Tuesday, June 29, 2021. I sincerely appreciate EPA’s invitation to participate, and the information provided to participants to evaluate potential rule changes and the process for their amendment.

The Texas Alliance of Energy Producers represents over 2,600 individuals and member companies in the upstream oil and gas industry; our members are oil and gas operators/producers, service and drilling companies, royalty owners, and a host of affiliated companies and industries in Texas and beyond. The majority of our members and board of directors work for, or own and operate small businesses as defined by the Small Business Administration.

We applaud EPA’s use of the Small Business Advocacy Review Panel to gather feedback from Small Entity Representatives to minimize negative impacts of regulation that would tilt the playing field in favor of larger corporations. This is particularly important for small businesses in the oil and gas industry who are producing a globally traded commodity. American small businesses are competing directly with international competitors, who in many cases, are operated by sovereign nations.

The cost estimates provided by EPA were helpful to guide discussions with Alliance members. In many cases, operators reported that those cost may be higher because the internal operations to adapt and conduct new regulatory requirements has been limited due to the contraction of the industry in 2020. The Alliance created and tracks a Texas upstream oil and gas economic index, and the employment data contained within indicates the loss of about 36% of direct upstream jobs in Texas in the 2019-2020 industry contraction. These limitations skew the cost estimate higher due to operators being more reliant on third-party contractors to facilitate revisions to emission controls not already required by state and federal law.

Finally, we would ask that EPA and SBA consider a forthcoming study conducted by the Department of Energy’s National Energy Technology Laboratory entitled “Quantification of Methane Emissions from Marginal (Small Producing) Oil and Gas Wells”: Project Number DE-FE0031702. The project is anticipated to end September 30, 2021 and we think the study’s finding will be beneficial to EPA in evaluating new controls for potential emissions from marginal wells.

Thank you again for the opportunity to provide comments on the Pre-Panel Outreach Meeting. The Alliance looks forward to helping EPA in the full Small Business Advocacy Review Panel process.

Jason Modglin
President, Texas Alliance of Energy Producers

THE PETROLEUM ALLIANCE OF OKLAHOMA

July 13, 2021

Submitted via email to: Wiggins.lanelle@epa.gov

U.S. Environmental Protection Agency
Attention: Lanelle Wiggins

RE: Small Entity Representative ("SER") Comments for the Environmental Protection Agency's ("EPA's") Forthcoming New Source Performance Standards ("NSPS") for the Oil and Natural Gas Sector

Dear Ms. Wiggins:

The Petroleum Alliance of Oklahoma ("Alliance") appreciates the opportunity to submit comments in response to EPA's Small Entity Representative Pre-Panel Outreach effort in advance of the forthcoming NSPS rule for the oil and natural gas sector.

The Alliance is the only trade association in Oklahoma to represent all sectors of the state's oil and natural gas industry. Representing more than 1,300 companies and their tens of thousands of employees, as well as 1,700 individual members, the Alliance's membership includes oil and natural gas producers, service providers to the oil and natural gas industry, midstream companies, refiners, and other associated businesses, and our members include companies of all sizes, ranging from small, family-owned companies to large, publicly traded corporations. The Alliance addresses industry issues of concern and works toward the advancement and improvement of the domestic oil and gas industry. We support and advocate for legislative and regulatory measures designed to promote the well-being and best interests of the citizens of Oklahoma and a strong and vital petroleum industry within the state and throughout the United States.

Many of our members are small entities that will be impacted by EPA's forthcoming NSPS OOOOa rule for the oil and natural gas sector. The following information provides our initial comments.

EPA's Current SER Process Timeframe is Inadequate

EPA's SER process for this rulemaking is too rushed to provide detailed information that EPA needs to make informed decisions about a new rule to reduce or minimize the impacts to small businesses. In other rulemakings, this process has taken (6 -9 months) providing adequate time for reasonable and appropriate input from small businesses. Executive Order ("EO") 13990 set an unreasonable time frame for EPA to develop a NSPS OOOOa rule that prevents small businesses from providing adequate input to EPA on such an important rulemaking that will have significant impacts. For EPA to fully understand the impacts to small businesses and to make informed rulemaking decisions, we call on EPA to request an extension from the White House regarding the EO timeframes for NSPS OOOOa rulemaking.

Oklahoma Small Businesses May Be Significantly Impacted by EPA's NSPS OOOOa Rule

EPA requested information that would improve its understanding of the number of small entities that could be affected by a new NSPS OOOOa rule. In Oklahoma, small businesses in the Mining, Quarrying, and Oil and Gas Extraction industry employ over 20,000 people, or over 50.5% of the private workforce employed in that sector in 2017.

New NSPS OOOOa Rule Should be Written Where Small Businesses Can Easily Comply

Federal regulations have become too complicated and complex for small businesses to understand without the help of consultants, especially as it relates to EPA's air rules. Typically, small businesses have limited staff and specifically do not have air experts on staff to easily manage air emission requirements. As a result, small businesses hire consultants or engineers to evaluate their operations and conduct the necessary requirements for compliance with NSPS OOOOa. The lack of plain language and overuse of complicated compliance mandates has many small businesses confused and overwhelmed. The NSPS OOOOa rule is not written in layman's terms nor use common oil field measurements e.g., the 6 tons per year threshold for tanks does not equate to something useable without the need to hire a consultant to conduct detailed calculations. For any future NSPS OOOOa rule, EPA should provide a rule that is clear, concise and uses plain language to enable small businesses to easily understand and comply with regulatory requirements.

Low Production/Marginal Wells Provide Significant Economic Contributions

Marginal wells are defined in federal law as oil wells producing 15 barrels per day or less and natural gas wells producing 90 thousand cubic feet per day or less. While these are the thresholds, states have more specific information. According to the Interstate Oil and Gas Compact Commission's ("IOGCC's") 2016 report on marginal wells, in Oklahoma, the average crude oil and natural gas production for a marginal well is approximately 1.43 barrels per day of crude oil and 18 thousand cubic feet of natural gas. Oklahoma has approximately 28,000 marginal crude oil wells and 45,000 marginal natural gas wells. Approximately 9.5 percent of Oklahoma's total crude oil production and approximately 12.0 percent of Oklahoma's total natural gas production comes from marginal wells. In addition, marginal wells provide a significant share of domestic oil and natural gas output and economic contributions. The IOGCC states that since approximately 2006, marginal wells have produced oil and natural gas valued at nearly $30 billion annually, or approximately 10 percent of the total value of oil and natural gas produced domestically. Because of well economics, a significant portion of these wells are operated by small businesses. It is important that EPA recognize and consider the importance of marginal wells to small businesses, the state and to the nation.

The initial production rate of oil and natural gas wells begins to decline as the resource is extracted from the reservoir. Consequently, its potential to emit methane and volatile organic compounds is highest when production begins and then declines over time. When EPA developed its NSPS regulations for oil and gas, it had no emissions profile for low production wells. No extensive profile yet exists. The Department of Energy (DOE) initiated a study of low production well air emissions that should be completed later in 2021. EO 13990 requires the Federal Government, "...be guided by the best science and be protected by processes that ensure the integrity of Federal decision-making." As such, EPA should defer regulating low production or marginal wells until the DOE study is complete. EPA must understand the low production/marginal well emission profile to determine if requirements are needed, and if needed, develop an appropriate national regulatory program. However, if EPA proceeds ahead with regulating low production wells or all wells, it should consider the following.

More Stringent Regulations on All Wells or One-Size-Fits-All Regulations May Have Unintended Consequences

It is unclear what EPA will propose in its forthcoming NSPS OOOOa rule. However, more stringent regulations on all wells, could lead to supply and demand issues that affect the cost and availability of control or monitoring equipment, especially on small businesses that operate low production wells/marginal wells. In addition, a one-size-fits-all rule that applies to all types of well is not appropriate or reasonable, is an inefficient use of manpower and funds, and it detracts focus away from high-emission sources where the highest environmental benefits could be obtained.

EPA Should Consider Alternative Leak Detection and Repair Requirements

Flexibility in the leak detection and repair ("LDAR") inspections program for low production wells should be considered that would reduce costs on small businesses e.g., upon completion of two successful (no findings) optical gas imaging inspections, the inspection interval requirement should be reduced to one time per year or every 2 years. EPA should allow for reduced inspections or exemptions based on the API gravity of the crude oil at a well site. In addition, EPA should allow for use of alternative monitoring e.g., functional testing of onsite equipment or audio/visual/olfactory methods by company personnel.

EPA Should Consider Alternatives for Certain Tank Scenarios

The current method for calculating maximum daily throughput for individual tanks (including water tanks) that are not manifolded/connected and controlled by a closed vent system and control device is unnecessarily burdensome, especially for low production wells and facilities connected to pipelines with a mix of trucked and pipeline-shipped liquids. Compliance with the NSPS OOOOa rule for these types of facilities connected to a pipeline would require tank-specific metering or intensive daily operating recordkeeping since tank gauging alone does not account for liquids sent through a lease automatic custody transfer unit. In addition, NSPS OOOOa control requirements for all tanks may result in higher greenhouse gas ("GHG") emissions (because of the combustion process) as compared to allowing uncontrolled (low methane content) tank emissions. From a greenhouse gas emission standpoint, in this scenario, it may be beneficial to remove the combustion device after demonstrating the tanks no longer need emission controls.

Regarding compressors that may be used for tank vapor recovery, some may be designed for use at low production well sites; however, they may require electricity to be used on location. In many remote areas, electricity to the well site is not always available or it may require substantial cost to get it to the well site. In other situations, utilizing a natural gas compressor may not be feasible as a marginal well may not produce enough gas to power the compressor unit. EPA should carefully consider the limitations at low production well sites before proposing these types of requirements on small business owners of low production/marginal well sites.

EPA Should Maintain the Recordkeeping and Reporting Provided in the Technical Rule

The changes in the technical rule that streamline the recordkeeping and reporting requirements are important to maintain for small businesses as it reduced the overall cost and administrative burden to operators (EPA cited 30 percent). Where compliance with state programs is deemed equivalent, no further recordkeeping or reporting should be required. Since electronic reporting through CEDRI is now required for NSPS OOOOa, particular attention should be given to the template to ensure that it does not call for additional information that is not otherwise required. In addition, EPA assistance and guidance with electronic reporting would be beneficial for small businesses.

EPA should consider the development of a fugitive emission monitoring tracking software program to aid small businesses to comply. Currently, there are "off the shelf" software programs; however, these are at an additional cost to small businesses.

EPA should ensure facility engineers within production companies can continue to certify the adequacy of the design of the closed vent system. These calculations may be completed in-house with the same simulation software that a consulting firm with a Professional Engineer would use.

EPA Should Ensure There is An Avenue Going Forward to Allow for New and Emerging Control and Monitoring Technologies

EPA should ensure there is an avenue going forward to allow for new and emerging control and monitoring technologies for all types of well. For example, alternative means of emission limitation technologies may potentially allow for multiple well inspections per day via drone/fixed wing versus traditional "boots on the ground survey". From a small business perspective, these new technologies must be cost effective, reliable, and easy to install and maintain.

Social Cost of Greenhouse Gases ("SC-GHGs")

In EPA's SER presentation, unit level cost estimates are provided for selected regulatory options under NSPS OOOO and OOOOa requirements. However, EO 13990 requires that agencies capture the full cost of GHG emissions considering the global damages in its decision-making process. It is unclear how any unit level costs would ultimately impact the outcome of a rulemaking using the SC-GHG analysis and how small businesses considerations and impacts are factored into this analysis. EPA should clearly provide details of how the SC-GHG analysis will impact small businesses.

EO 13990 Prioritizes Environmental Justice

We look forward to working with EPA in the development of a NSPS OOOOa rule that provides the fair and equitable treatment and meaningful involvement in the rulemaking process as it applies to small businesses.

Conclusion

The Alliance appreciates the opportunity to provide SER comments to EPA. If you have questions, please contact me at angie@okpetro.com or 405-601-2124.

Sincerely,

Angie Burckhalter

Angie Burckhalter
Sr. V.P. of Regulatory and Environmental Affairs

cc:
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Cumberland Valley Resources, LLC
2647 Cherokee Parkway, Louisville, KY 40204

Lanelle Wiggins <Wiggins.Lanelle@epa.gov> July 12, 2021
US EPA Office of Policy
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Re: Pre-Panel Comments on Oil & Natural Gas Sector New Source Performance Standards

Dear Lanelle,

Thank you and the SBAR Panel for the opportunity to comment on potential changes to the New Source Performance Standards for the Oil & Natural Gas Sector. As you know, I participated as a SER in the 2015-2016 SBAR, and was disappointed when EPA decided not to exempt low production/stripper wells from Quad Oa. Since then, I have been included in several meetings with EPA, both in DC and Raleigh, to try and better inform EPA representatives as to the construction and operation of shallow, conventional, oil and/or gas wells typical of Kentucky (and much of the Appalachian and Illinois Basins), and their differences compared to oil and gas wells in other hydrocarbon producing areas of the Country.

My company, Cumberland Valley Resources, LLC, was started in 1999 and is owned by my partner and myself. I have been in the oil and gas business since 1980, and I am a past President of the Kentucky Oil & Gas Association and a current board member. In 2016 we owned and operated over 300 oil and gas wells in Kentucky, and employed 16 people. From 2005 to 2010, a time frame of strong oil and gas prices, we drilled approximately eight new oil or gas wells per year. From 2011 to 2015, after natural gas prices declined badly, we continued to drill only two or three oil wells per year. We have not drilled a new oil well since 2015 and haven't drilled a new gas well since 2010. In 2018 we divested our oil producing properties, but continue to operate approximately 60 gas wells with a staff of 4. Operation for us over the last twelve years has depended on the reduction and in some cases, elimination of operating costs on our low volume wells. By far, most of the wells we have drilled, from initial production on, would be considered stripper wells. Those few oil wells we drilled where we were lucky enough to begin production at a rate over 15 barrels of oil per day, declined within the first year of production to be considered stripper wells. But, within a few years of initial production, typical of the low permeability low pressure reservoirs we have, the average annual production decline becomes very low. Our gas wells are similar, but it is very rare that a Kentucky gas well's actual initial production would be over 90 Mcf/day, and requires compression to produce. We have operated both oil and gas wells that were over 100 years old and still producing marketable quantities.

There are many thousands of small operators in the Appalachian and Illinois Basins, over 1,000 in Kentucky, most similar to what we are, "mom and pops", with small staffs, little technical education, but very experienced and entrepreneurial. There are no major oil companies currently operating in KY, and less than 10 operators that might not qualify as a "Small Business". KY operators have historically made good livings, producing a significant portion of the United States' natural gas and oil supply, but are very dependent on keeping operating costs low, especially in today's climate of low natural gas prices and wildly fluctuating oil prices. Current gas prices are similar to what they were back in 1998 and 1999, but operating costs are significantly higher than they were in the late 90's. We are hoping that natural gas prices which have increased lately, will continue to increase and stabilize at some amount over $4.00 per Mcf. At that point we feel that we will begin to see investment in drilling new gas wells in Kentucky, re-employing a significant number of people in rural areas of our basins that had been left without jobs when oil prices began to collapse in 2015, and adding volume to domestically produced energy. Again, this investment will be dependent on keeping drilling costs and operating costs low, including any new cost of regulation.

In June of 2016 when EPA finalized Quad Oa, it was apparent Quad Oa's NSPS were going to present many new and expensive compliance issues to operators that might drill new low production wells. The most troubling issues are; fugitive emission surveys, recordkeeping, use of combustors, and the definition of Well Site Modification. All of these requirements were designed to limit methane emissions from high volume, high pressure wells and facilities that have the potential to emit a significant amount of methane from a leak or during flow back after being reworked or fracked, or from storage facilities into which significant amounts of oil is being produced and stored. Those types of emissions are significant and it makes sense to control them from both an environmental and economic point. Operators of those types of wells and facilities have or can easily afford the personnel to oversee those types of surveys, purchase the equipment necessary, and complete the recordkeeping required by EPA. But the typical operator of low production wells drilled in our basins with a low potential to emit methane from leaks, or frack flow back, has a very small staff, decimated by years of low commodity prices, cannot afford the costs of Quad Oa compliance and does not have the staff to fill out and keep updated records that EPA is requiring. The annual reporting spreadsheet, "60.5420ab_annual report_v3", is daunting to a small operator and very little of it is applicable to their operation.

The average gas well in Kentucky has an initial production of less than 50 Mcf/day and within a few years is producing 10 Mcf/day or less. Gas gathering systems in KY are constructed using plastic pipeline with a maximum pressure of 100psi, but are most often operated at pressures less than 25 psi. Low volume well wellheads, which are constructed in a very efficient and safe manner, include small numbers of brass and steel fittings and valves threaded together (dozens of 2" components not hundreds of larger components like used on high volume/high pressure wells). Threaded connections in the low pressure piping, when doped and tightened properly, very seldom leak. In the unlikely situation when something catastrophic (ie: tree falling) occurs and a leak develops, it is usually very small (small bubbles become visible when soap water is applied to the fittings) and can be usually eliminated by tightening the leaking connection. Hence, the potential volume of methane that might be emitted from a thread leak of a low pressure wellhead can hardly be compared to the volume from a similar leak from a high pressure well with thousands of pounds of pressure. Yet, Quad Oa requires both wells to have similar expensive LDAR programs, utilizing optical equipment that is still not easily available or affordable to the small operator. Current Quad Oa fugitive emission survey requirements are overkill for low production/low pressure gas wells, and will do little to reduce fugitive emissions. I believe a study on fugitive emissions from stripper wells, initially funded by the Dept. of Energy and being performed by its contractor GSI, reportedly to be completed this year, will prove the insignificance of fugitive emissions from stripper wells like ours.

Very few if any of the tank batteries collecting oil from the thousands of stripper oil wells in KY reach the 6 tons per year threshold requiring vapor recovery and combustion, and those that do only produce at that volume for a short period of time. However, the addition of a new oil well producing into an existing tank battery may trigger the need for fugitive emission surveys, even though emissions from the tank are unregulated. This required survey and its record keeping are a burden on the operator and does nothing for the control of fugitive methane emissions.

Wells in other areas that begin production at much higher volumes, may eventually decline to become stripper wells, depending on operating costs. The revenues during times of higher production volumes allow for the additional costs of Quad Oa compliance. But once the wells production has reached stripper well production levels, its potential to emit fugitive emissions will have also diminished, and a less expensive method of a fugitive emission survey may allow for many more years of economic production from that well. There should be a path that all wells, even those with large initial production volumes can reach a point of less costly compliance requirements.

It is my belief that Quad Oa NSPS regarding fugitive methane emissions as applied to low volume/low pressure wells are neither warranted nor justifiable. The tens of thousands of wells in KY that produce less than 10 Mcf or 1 barrel of oil per day and have for decades beyond initial production, are significant to our state. The operators of these wells cannot bear the additional cost of bi-annual or even annual optical gas imaging surveys and the additional recordkeeping required under Quad Oa and be profitable. Quad Oa requirements as they are could condemn the future of Kentucky's conventional oil and gas industry.

Stripper wells should continue to be exempt from Quad Oa's requirements including fugitive emissions surveys or at least a separate classification or sub category should be developed to allow the operators of the low volume wells to use simple common sense solutions to periodically check for fugitive emissions, that don't require additional personnel or equipment.

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CountryMark

Indiana Oil & Gas Association

KOGA

Oil and Natural Gas Sector New Source Performance Standards
Small Entity Representative Pre-Panel Comments

40 CFR Part 60
Lanelle Wiggins, United States EPA (Wiggins.lanelle@EPA.gov)
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CountryMark is a small oil production, refining, and marketing company based in Indiana. CountryMark is owned and controlled by its member cooperatives that are in turn owned and controlled by individual farmers within our trade territory. Over 140,000 farmers in Indiana, Michigan, Ohio, Illinois, and Kentucky participate in these local cooperatives who own CountryMark. Our Board of Directors is comprised of farmers and member cooperative leaders. Each year, profits are distributed back to these farmers via the cooperative system. These distributions remain in local communities where the dollars support local economies. CountryMark purchases approximately 80% of the Illinois Basin production, whereby more than 40,000 royalty owners are paid based upon their mineral interest.

Our refinery processes 30,000 barrels of crude oil per day which represents only 0.15% of the entire domestic refining industry. Even though CountryMark is small from a refining industry perspective, we have a large impact on the State of Indiana. CountryMark supplies over 70% of the agricultural market fuels and 50% of school district fuels in the state.

Energy Resources, LLC, as a subsidiary of CountryMark, produces approximately 5% of the oil that is processed at CountryMark's refinery. As an oil producer, Energy Resources is required to comply with rules and regulations from three different states, the Bureau of Land Management (BLM), and the US EPA.

CountryMark meets the definition of a Small Entity Representative. The comments submitted are from our perspective, as a small business, about how additional rules covering existing sources could impact the way that we do business.

The Indiana Oil and Gas Association (INOGA) has a rich history of involvement in the exploration and development of hydrocarbons in the State of Indiana. INOGA is an all-volunteer organization formed more than 65 years ago. INOGA represents more than 125 companies participating in the oil and gas business segment throughout the state of Indiana. Participating members include representatives from oil and gas exploration and development companies (operators) as well as companies working in the following sectors: pipeline, refinery, land acquisition, service, supply, legal, engineering and geologic services. We represent our members in relation to local, state, and federal regulation and legislation affecting the industry. Almost all of our members meet the definition of a Small Business. We present a unique perspective for EPA and SBA to consider as new regulations will have a large impact upon most of our membership.

The Kentucky Oil and Gas Association (KOGA) represents the interests of its members who are primarily small independent producers of natural gas and oil production that operate predominantly low volume/low pressure wells across the Commonwealth of Kentucky. KOGA members are dedicated to the responsible production and conservation of Kentucky's natural resources by ensuring that our members are provided fair regulations, while protecting individual property rights, health, safety and the environment.

CountryMark, INOGA, and KOGA all appreciate the opportunity to be involved in the rule making process as a small business entity or representing other small business entities and to provide our comments to EPA and SBA related to the upcoming regulation.

Contents

Solicitation for Comments:

EPA and the SBA initiated a conversation with small business entities as part of the rule making process to extend emissions control requirements past oil and gas wells that have been constructed since the fall of 2015 to existing sources. EPA has presented several topics to industry to collect additional data as the proposed rule package is being developed. Below are comments developed on behalf of Countrymark Energy Resources, LLC, the Indiana Oil and Gas Association (INOGA), and Kentucky Oil and Gas Association (KOGA) to address areas that EPA has solicited feedback and areas that we have concern with the proposal to extend emissions control requirements to existing sources.

EPA has solicited specific comments from industry to further develop their understanding of our industry as they are developing the regulatory framework. Below we provide our perspective on topics that specifically apply to CountryMark's operations and INOGA's and KOGA's membership that EPA has requested input.

Is there any information that would improve our understanding of the number of small entities that could be affected by this action?

Countrymark Energy Resources, LLC operates oil wells in Indiana, Illinois, and Kentucky. Most of the companies that we do business with meet the Small Business Size definition for NAICS 211120 (crude petroleum extraction), 211130 (natural gas extraction), 213111 (drilling oil and gas wells), and 213112 (support activities for oil and gas operations).

All of the major oil and gas companies left the Illinois Basin decades ago to find large production fields, leaving small business entities behind to operate mostly stripper wells throughout the three state region. Any action taken will impact a large majority of companies operating in the Illinois Basin as a small entity. This action impacts oil and gas operating companies as well as the service companies that support the day to day operations of the production companies. Reduction in oil production throughout the Illinois Basin as a result of additional regulatory burden also directly impact more than 40,000 royalty owners that regularly receive payments associated with production from their mineral interests.

Indiana Oil and Gas Association Board of Directors is comprised of sixteen companies directly involved in oil and gas exploration and production as well as service companies. Each of the companies represented by a Board member meets the definition of a Small Business Entity. INOGA represents more than 60 companies operating in Indiana. All but two of the companies meet the definition of a Small Business Entity.

Kentucky Oil and Gas Association Board of Directors is comprised of twenty companies directly involved in oil and gas exploration and production as well as service companies. Nineteen of the companies represented by a Board member meet the definition of a Small Business Entity. KOGA represents more than 108 companies operating in Kentucky. All but ten of the companies meet the definition of a Small Business Entity.

What recommendations do you have for reducing recordkeeping and reporting burden on small businesses?

This is a really important point for EPA and the SBA to consider – many small businesses have not been required to comply with OOOOa because they have not drilled and hydraulically fracture stimulated wells since the fall of 2015. Extending the regulations to existing sources, many with de minimis emissions, will now bring many businesses into a compliance world that they have never had to operate in the past. The documentation and reporting portion of this regulation will be a very challenging endeavor for most of the oil and gas operators that are small business entities.

Most small businesses do not have a sufficient staff to complete all of the documentation and reporting requirements for OOOOa, no less documentation and reporting requirements for all existing sources. The additional regulatory burden will require many small businesses to hire additional staff or hire contractors just to meet record keeping and reporting requirements. This additional financial burden brings no opportunity to increase revenue to the business, only additional cost overhead to meet compliance requirements.

We appreciate the reduction in recordkeeping and reporting requirements that EPA implemented in the 2020 Technical Revision of OOOOa. This change was a meaningful first step in eliminating redundant and non-value added work for industry. We appreciate EPA's 30% reduction in recordkeeping and reporting requirements from the 2020 Technical Revision to OOOOa. We encourage EPA to collaboratively work with industry to implement additional reduction to recordkeeping and reporting where data collected does not further support the reduction in emissions. We are willing to continue the conversation with EPA to identify and eliminate non-value added recordkeeping and reporting activities during the development of the upcoming regulation.

The original OOOOa template that EPA provided in the CEDRI reporting template consisted of 179 columns of data that needs to be completed annually. The updated template has been reduced to 166 columns of data. Not every column must be completed by every operator because the operators do not operate every type of facility (i.e. some operators do not have centrifugal compressors or pneumatic pumps). However, time must be spent evaluating the data input for every column. Each column has the capability to store multiple data points specified by EPA.

OOOOa was issued with a "one size fits all" approach. Over the past six years, we have demonstrated that this method does not work. There is too much diversity in the oil and gas industry for a regulation to generally cover all on-shore oil and gas operations. We have consistently advocated for a simple bifurcation of the rule to provide regulatory relief for Small Business Entities. Most of the wells operated by Small Business Entities are low production wells with de-minimis emissions profile compared to the high production wells. Creating a separate category for Small Business Entities will meet the requirements to reduce the burden for small businesses because most of the low production wells (i.e. stripper wells) are owned and operated by small business entities.

What can you tell us about the OOOOa control technologies, their costs, and their effectiveness at reducing emissions? Are there any other technical considerations we should be aware of?

Tank Battery Monitoring

OOOOa requires Optical Gas Imaging (OGI) for all affected well sites and tank facilities. For most of the stripper wells, or low production wells, the affected facilities have emission rates below EPA's threshold of 6 tons per year (tpy) to safely and reliably operate a combustion unit. In these cases the tanks are equalized with the atmosphere through an atmospheric vent. The emissions profile for these tank facilities is very small compared to high volume production wells.

CountryMark operates 363 tank facilities, with less than five facilities requiring the installation of combustion units. Twenty four of the facilities are considered affected facilities under OOOOa. We are required to perform OGI inspections on the affected facilities, even though they have a legal vent to the atmosphere. This is an expensive and non-value added activity. OGI inspections are an expensive option to inspect facilities for emissions as well as the associated documentation and reporting requirements.

We recommend that EPA change the requirements for these facilities owned by Small Business Entities to use Olfactory-Visual-Auditory (OVA) inspections or soap bubble tests to ensure that tank hatches are shut and other leak sources are secure. Implementing this change will significantly reduce costs of compliance as well as documentation and reporting costs for small business entities. The additional cost for CountryMark to inspect an additional 339 facilities (363 total facilities – 24 affected facilities) each year at EPA's estimated cost for semiannual OGI monitoring of $2,368 p*er well site with amortized capital cost* (inspecting a tank facility is the same as inspecting a well site) increases annual our compliance cost by more than $800,000 (339 facilities x $2,368/facility) without any meaningful environmental benefit. This type of additional compliance cost can be detrimental to small businesses.

We estimate that the inspection cost may be reduced by as much as 50% by permitting OVA and soap bubble testing at tank facilities associated with low production well sites. The cost savings will come through our trained employees performing the inspections during already scheduled daily or weekly inspections of the facilities. Independent contractors with expensive OGI equipment and certifications will not need to be scheduled, paid for their travel time and time on location, managed as they are on our work sites, and develop reports for our staff to review and address deficiencies. This compromise in inspection technique will not result in a measurable increase in emissions because tank emissions are already less than 6 tpy, indicating that the potential to emit is already low enough to not be able to reliably support a combustion system.

Table 1 shows the results of CountryMark's prior four year OGI inspection history, which has been submitted to EPA through CEDRI during the annual reporting process. The table shows the number of Fugitive Emission Components found to be leaking at a well site or tank battery during the inspection. Using and average of 15 Fugitive Emission Components for tank batteries and 50 Fugitive Emission Components for well sites, less than 1% of the Fugitive Emission components have been found to be leaking in any given period. The leaks are generally challenging to detect with OGI because of low production rates, low wellhead pressure, and low Gas to Oil ratio in the Illinois Basin. With four years of data from inspections, we submit to EPA that the environmental benefit is not as great as EPA estimated in the promulgation of OOOOa.

Year	# of Leaks	Components Inspected	Failure Rate
2020	6	4,815	0.1%
2019	14	3,700	0.4%
2018	9	2,925	0.3%
2017	9	1,195	0.8%

Table 1. Annual OGI Inspection Findings

We estimate that the cost to complete OGI monitoring of the well sites and tank batteries is approximately $75,000 per year. This cost includes amortizing an OGI camera, training an employee and vehicle cost, insurance cost, and documentation and reporting costs. With the cost incurred to identify and repair fugitive emission components, we have realized no financial benefits from an increase in production. Most small business entities cannot absorb an additional $75,000 per year in compliance cost without realizing a return on their investment.

Propane Requirements for Combustion Systems

OOOOa requires that propane is utilized to maintain a pilot light for combustion systems. For most low production wells, more propane is consumed than gas is burned at the flare for a combustion system. This results in more emissions generated and additional compliance costs for small operators. Following this business practice also increases emissions from propane being delivered to the combustion facility and from additional inspection requirements set forth by EPA. The requirement for a continuous pilot is not environmentally preferred, nor is it always cost effective.

For low production wells, the operator should determine if propane is required to support flare systems based upon safety requirements, not regulations that were published using a "one size fits all" methodology. Companies should be able to make the decision about using propane based on safety and system operability, not based upon a regulation.

Utilizing propane to maintain a continuous pilot has put the public at risk over the past five years. During times of severe cold throughout the United States, propane shortages have been experienced. Propane has been directed to meet OOOOa requirements for a continuous pilot instead of meeting the heating needs for households that utilize propane as a primary heating source.

Do you have any other feedback for EPA?

Orphaned Wells:

EPA has indicated that a program is being developed for existing oil and gas sources, which may be similar to OOOOa. Will this program also require states to monitor orphaned wells? The REGROW Act (Revive Economic Growth and Reclaim Orphaned Wells Act of 2021) estimates that more than 56,000 documented orphaned wells exist across the country. The Act will be used to plug many of the orphaned wells, but this work cannot be completed by the time that the proposed rule will become effective.

If states decide not to accept REGROW Act funding, orphaned wells will continue to be plugged at a rate that the state is capable of plugging the wells. In this case, what will EPA's requirements be for states to monitor the orphaned wells? We recommend that any potential costs that may be incurred to monitor orphaned wells may also be used to plug the wells.

Indiana currently is responsible for approximately 1,150 orphaned wells. Using EPA's cost for semiannual OGI monitoring of $2,368 p*er well site with amortized capital cost*, this will be an additional annual $2.7 million in compliance cost to Indiana DNR's operating budget to monitor orphaned wells. Kentucky has an estimated 14,000 orphaned wells to plug. The cost to monitor the orphaned wells for Kentucky will exceed $33 million per year (14,000 wells x $2,368 per well). The additional compliance costs will greatly strain the states' already limited resources. These orphaned wells have almost no emissions because they have been abandoned by operators in prior years.

We assume that this cost of compliance will be passed on to oil and gas operators through greater fees imposed by the state agencies. With almost all of the oil and gas operators in Indiana and Kentucky being small businesses, this will be another cost of compliance with no measurable environmental benefit. We recommend that orphaned wells be exempted from any monitoring requirements that EPA may be considering.

Overall Compliance Costs:

As of July 1, 2021 Indiana has approximately 7,550 wells that are not considered orphaned wells. Only a small fraction of the wells are currently considered affected well sites or facilities under OOOOa. Using EPA's cost for semiannual OGI monitoring of $2,368 p*er well site with amortized capital cost*, this will be an additional annual $18 million in compliance cost for oil and gas operators (7,550 well sites x $2,368/well site). This estimated cost does not include the additional cost to inspect tank facilities. During 2019, total oil production from the Illinois Basin in Indiana was 1.58 million barrels. With an average Illinois Basin crude oil price of $50/barrel, operators received a gross revenue of $79 million (1.58 million barrels x $50 / barrel) – this is before royalties, taxes, and operating costs are paid. EPA's proposal to add compliance requirements to existing sources will result in approximately 23% ($18 million / $79 million) of an operators' Gross Revenue being spent on compliance costs with very little emissions benefit.

At the end of 2018 Kentucky had approximately 30,000 oil and gas wells throughout the state. The annual compliance cost for Kentucky Operators will be an estimated $71 million (30,000 wells x $2,367 / well site). This estimated cost does not include the additional cost to inspect tank facilities. During 2018, annual production was approximately 3 million barrels of oil and 1.6 BCF of gas. The average price of oil in 2018 was approximately $58/barrel and the average gas price was approximately $3/MCF. Gross revenue for operators was approximately $179 million (3 million barrels x $58 barrel + 1,600,000 MCF x $3 / MCF). EPA's proposal to add compliance requirements to existing sources will result in approximately 40% ($71 million / $179 million) of an operators' Gross Revenue being spent on compliance costs.

This is an annual cost, not a one-time cost. Most small business entities cannot absorb costs of this magnitude and continue to operate their business. This could be perceived as an excessive enforcement of federal regulations on small businesses. We are advocating that the low production well exemption from the 2020 Technical Revision of OOOOa be maintained. This exemption will provide regulatory relief for small business entities without a significant compromise in environmental benefits.

CountryMark can speak directly to the cost burden of EPA's programs. We operate a refinery as well as Oil Exploration and Production company. Many years in the past decade, we have incurred more annual cost for compliance throughout our Refining and Oil Production entities than we have made as a profit for the given years. We are advocating for EPA to consider the cost of compliance for programs that are being developed and already exist. These compliance costs materially impact our ability to return value to our owner-members each year. Many of the small businesses operating in the Illinois Basin will not be able to absorb the additional cost of compliance.

What are the characteristics of a small business that makes it different from a large business?

Most of the small businesses operate low production wells, or stripper wells. These wells produce less than 15 barrels of oil per day. The emissions profile from these low production wells is very low compared to new wells that have been drilled and completed using high volume hydraulically fracture stimulated completion methods.

The stripper wells are typically conventional wells, or vertical wells, compared to the unconventional wells also having a very long horizontal well bore. Conventional wells typically have a small exposure to oil and gas reservoirs, compared to horizontal wells. This exposure physically limits the amount of oil and gas that can be transported to the wellbore, reducing the potential emissions from the well.

Many of the stripper wells are operated in basins that have been exploited for several decades. Production in the Illinois Basin has been ongoing for more than 115 year, with major production beginning in 1905. The Illinois Basin is considered a mature basin because most of the major oil and gas fields were discovered decades ago. The basin is low pressure with very little gas remaining; lower pressure means a smaller driving force for emissions. Small businesses operating oil wells in the Illinois Basin have a significantly lower Potential to Emit (PTE) than unconventional other basins found in states such as North Dakota and Texas. This can be readily seen by the quantity and size of flares at well sites or by the volume of gas that is sold from these basins. Very little of the associated gas is collected and sold in the Illinois Basin because the quantity is so small that companies cannot justify investing in the infrastructure to process the gas and transport it to market.

What recommendations do you have for small business flexibilities?

CountryMark, INOGA, and KOGA recommend the following for small business flexibilities:

- Maintain the low production well exemption, based on twelve months rolling average production, not the initial production of the well.
- Continue to work collaboratively with industry to reduce record keeping and reporting activities.
- Implement an annual OVA and soap bubble test for low production wells and associated tank facilities to reduce the OGI inspection cost and record keeping costs.
- Eliminate the requirement for propane to be utilized as a supplemental fuel source for combustion system pilot lights. Enable operators to make this decision based upon a safety decision, not a compliance decision.
- If the proposed regulation includes significant requirements for Small Business Entities, we recommend that EPA provide additional time for implementation. Based upon our experience, we recommend that Small Business Entities have one year to develop and implement compliance programs. When EPA implemented OOOOa in 2016, operators were only given 60 days to develop and implement the program. With many new operators that will likely be impacted by this regulation, the implementation schedule should be extended. Many small business operators will require additional time to understand the regulation and develop a compliance program to meet EPA's requirements. EPA has utilized this method in implementing other regulations, such as the Tier III gasoline requirements where small refineries had an additional three years to comply with the regulation.
- We recommend that EPA maintain flexibility in the rule development to be able to include results and findings from the Department of Energy (DOE) study commissioned in 2019. The study was commissioned to evaluate emissions from low production wells across the United States. The final results are due to be released in late 2021. The study results were delayed due to COVID-19 travel restrictions. President Biden has issued an arbitrary date of September 2021 for EPA to develop new regulations for existing sources. Issuing the final rule without considering the results of the study may be considered arbitrary capricious.
- We recommend that EPA consider reducing the OGI inspection requirements for small business entities from twice per calendar year to once per calendar year. OVA inspections may be performed by field staff during regular inspections of the well sites. If a potential leak are identified, soap bubbles may be used to verify and locate the source and repair between OGI inspections. We estimate that this change will reduce small entity OGI inspection costs by up to 50%. EPA previously considered reducing inspection frequency.
- Do not require states to monitory orphaned wells. The wells are typically low pressure and do not present a high environmental risk.

- Do not develop a “one size fits all” regulation, whereby requiring expensive compliance programs on sources that have little Potential to Emit. Small Business Entities operate a large majority of the low production wells. EPA needs to consider the cost implications for requirements such as OGI on small business entities and the potential environmental benefit realized by the new requirements.
- Clarify the definition of Hydraulically Fracture Stimulate. The current definition is: *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. Most of the formations in the Illinois Basin are not geologically considered to be “tight, such as shale or coal”, and do not experience “high rate, extended flow back”. Clarifying this definition could provide measurable regulatory relief for many small business entities of conventional wells. We believe that some of the conventional well stimulation methods should be exempted from EPA’s definition in OOOOa.

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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.

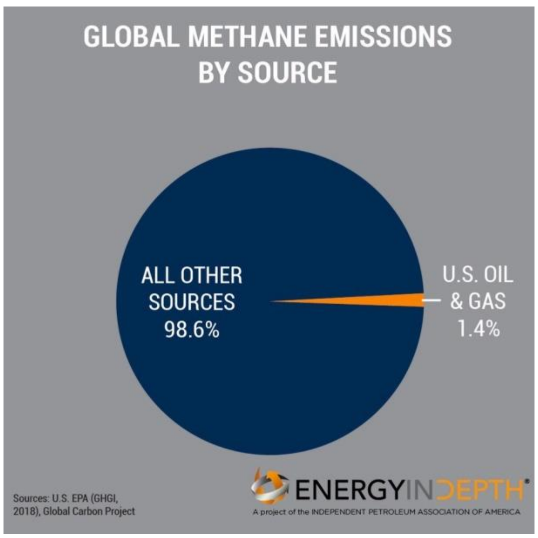
According to the **National Oceanic and Atmospheric Administration** and the **Global Carbon Project**, wetlands are the world's largest source of methane emissions. Natural sources make up 40% of all emissions. The remaining 60% are related to human activities including agriculture. ***Fossil fuel production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

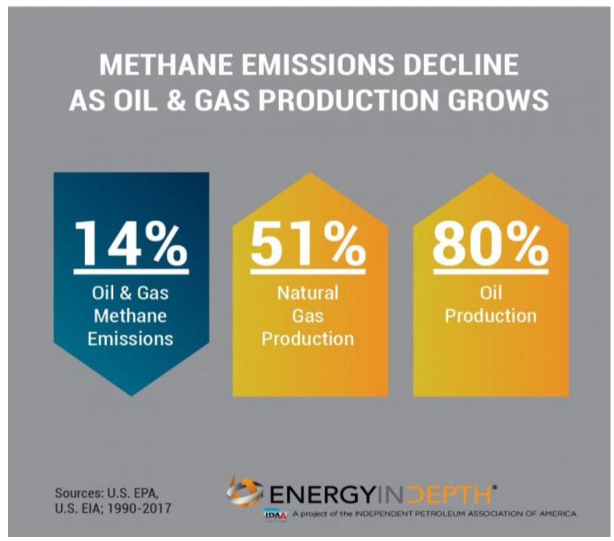
In the United States, that share is even smaller. The EPA's greenhouse gas reporting data show that the aggregate share of the inventory for oil and natural gas is about 3% and, importantly, the production share is just 1.22% of U.S. GHG emissions.

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.

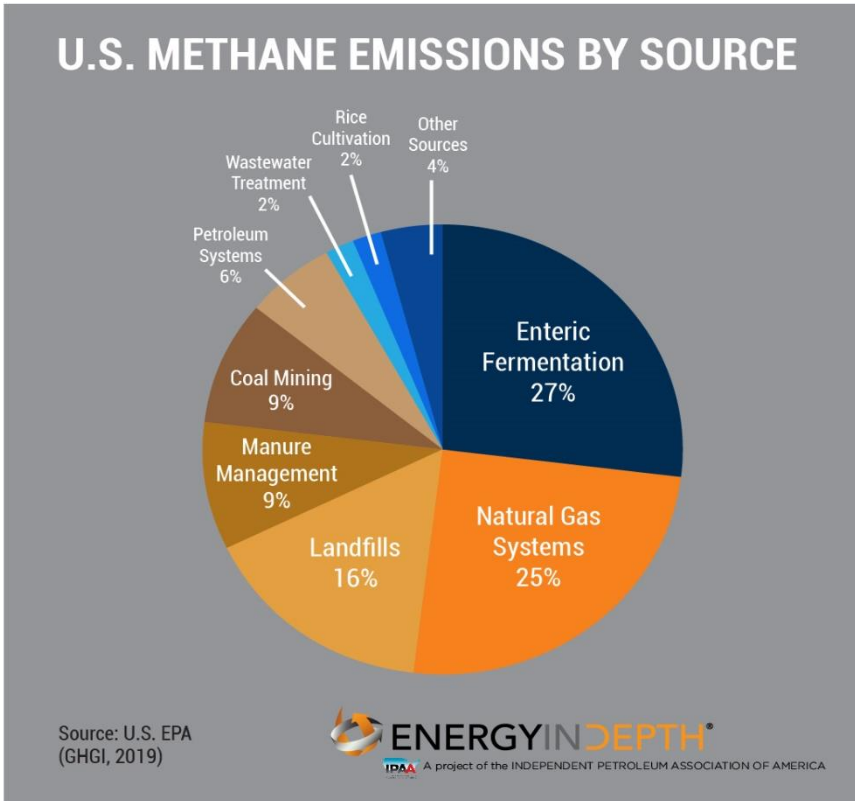
As stated above, EPA requires digital photos and reports to be stored for up to five years. Development of a data management system, purchasing of additional data storage systems, and user training will require greater than 600 - 800 man hours. At a fully loaded cost (salary and benefit) of $60 per hour,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

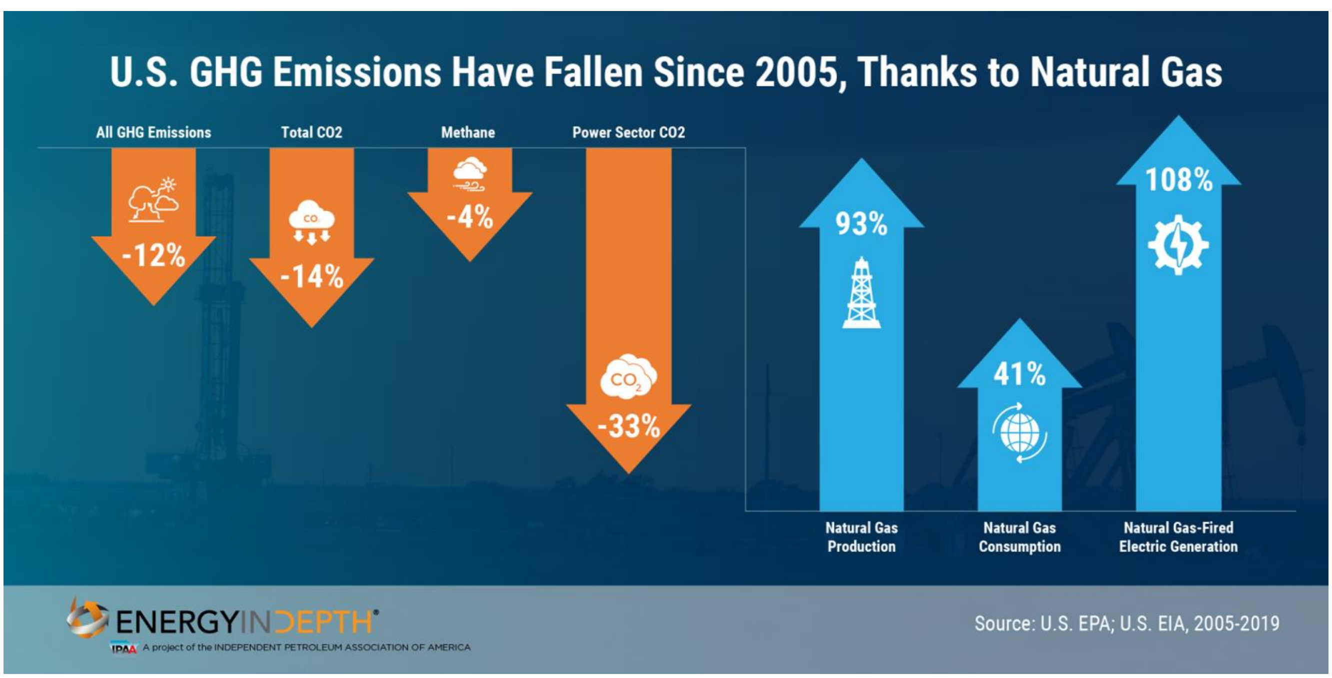
We question the value of some of the information that operators are required to collect. A sample of this is provided below:

- 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%
Natural Gas Systems 25%
Landfills 16%
Source: U.S. EPA (GHGI, 2019)
ENERGYINDEPTH
IPAA A project of the INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA


U.S. GHG Emissions Have Fallen Since 2005, Thanks to Natural Gas
All GHG Emissions
Total CO2
Methane
Power Sector CO2
-12%
-14%
-4%
-33%
93%
41%
108%
Natural Gas Production
Natural Gas Consumption
Natural Gas-Fired Electric Generation
ENERGYINDEPTH
IPAA 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

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

MICHIGAN OIL AND GAS ASSOCIATION
124 W. ALLEGAN ST., SUITE 1610 • LANSING MI 48933 • Telephone: (517) 487-1092 • Fax: (517) 487-0961

July 13, 2021

Ms. Lanelle Wiggins
Environmental Protection Agency
USEPA Headquarters
William Jefferson Clinton Building
1200 Pennsylvania Ave., NW
Mail Code: 1806A
Washington, DC 20460
*Submit via email to wiggins.lanelle@epa.gov

Re: *SER Response for the Small Business Advocacy Review (SBAR) Panel Process regarding Executive Order 13990.*

Dear Ms. Wiggins,

Please accept the following discussion provided by the Michigan Oil and Gas Association (MOGA) with regard to Executive Order 13990 and proposed amendments to Federal New Source Pollution Standards (NSPS), Subpart OOOOa.

The Michigan Oil and Gas Association (MOGA) is a trade organization that represents a large majority of small business entities engaged in the exploration, drilling, production, transportation, processing and storage of crude oil and natural gas within the State of Michigan.

MOGA is participating as a small business representative (SER) on the Small Business Advocacy Review (SBAR) Panel Process required under the Regulatory Flexibility Act (RFA), as amended by the Small Business Regulatory Enforcement Fairness Act (SBREFA).

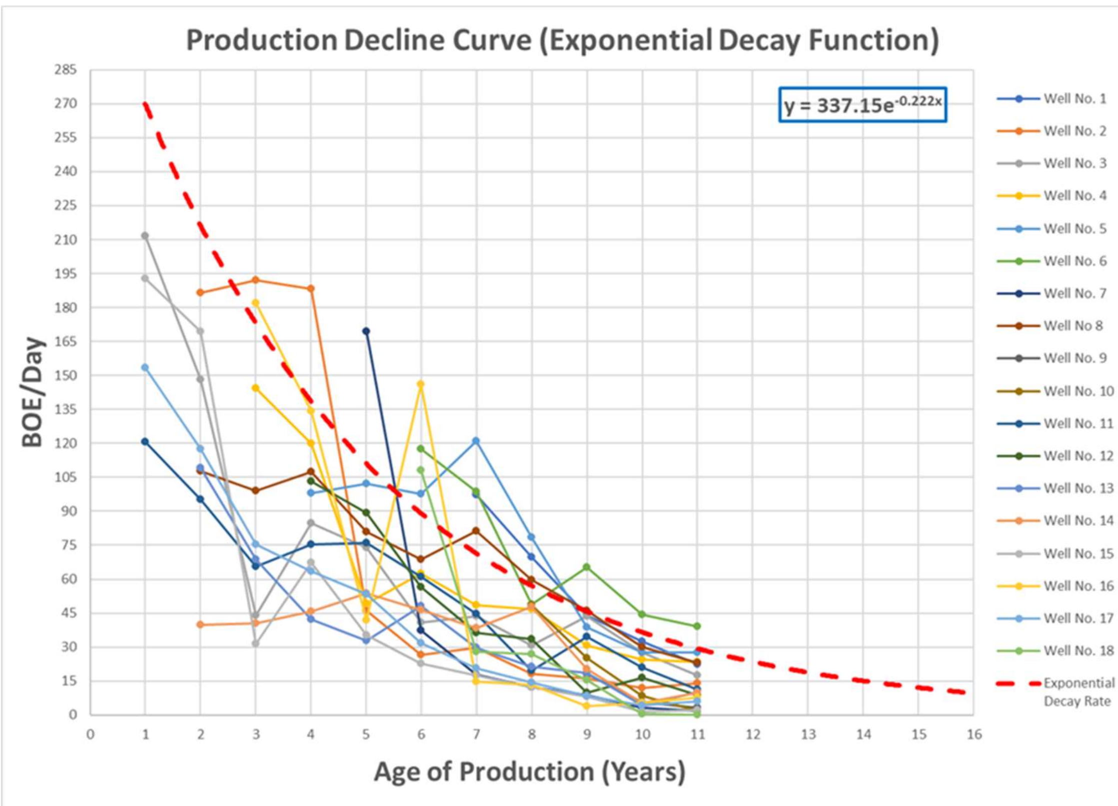
MOGA would like to thank the Small Business Administration (SBA) for the opportunity to comment and appreciates the ongoing support and advocacy of small businesses which constitute a large majority of Michigan's oil and gas producers.

The following topics are presented to provide evidence with examples to assist the SBA in advocating for the mitigation and prevention of exorbitant cost burdens that will have a significant negative economic impact on every small oil and gas entity in the State of Michigan.

<u>Production Decline</u>

Production decline, increased costs associated with artificial extraction techniques and the diminishing cost correlation related to increased Federal regulations are the primary concerns of all small entity oil and gas producers within the Michigan Basin. Understanding this cost dynamic is paramount to understanding MOGA's arguments for marginal well exemption and against the proposed NSPS expansion to existing wells.

In the Michigan Basin, initial oil and gas production from a new well can decline quickly. To illustrate this fact, MOGA evaluated the barrels of oil equivalent per day (BOEPD) for 18 oil wells drilled between 2007 and 2017. The graph below displays the rapid production decline over 10 years.



Statistical evaluation of the data using an exponential decay function suggests a BOEPD decline rate of approximately 20% annually over the first 10 years. However, as oil and natural well production advances in age, the production decline diminishes and begins to plateau as the geologic producing horizon reaches an equilibrium. In many cases, this stabilized production requires additional processes and associated cost increases to maximize the recovery of the remaining reserves.

The extrapolation of the exponential decay rate beyond Year 11 indicates that BOEPD achieves low-production status around Year 15 with future production directly tied to cost minimization. At this point, the negative correlation between production and costs creates an economic viability issue. Once a well reaches low-production status, continued production and viable life of the well are dependent on cost minimization. Many of the wells depicted above would continue to perform after the original 15 years with carefully managed costs focused on properly maintained operating equipment, formation analysis and production scheduling.

MOGA's constituents argue that the increase of additional costs associated with maximum resource extraction combined with unjustified, exorbitant and burdensome regulatory compliance costs of an expanded NSPS will undoubtedly lead to wasteful management practices of plugging and abandoning of well assets. This will have a significant negative economic impact on all small producer entities in the State of Michigan.

To further illustrate the tertiary impacts of declining production related to possible emissions, MOGA evaluated the working, standing and breathing emissions from storage tanks associated with production from the 18 Michigan wells shown in the table above. The following table displays the Well No., Age of Well on December 31, 2017, Total Hydrocarbon emissions in tons per year (tpy) calculated during the first 30-days of production, Total Hydrocarbon emissions from the last 30-days of production from 2017, and the percent change (decline) in Total Hydrocarbon emissions.

Well No.	Age of well (As of Dec 31, 2017)	E&P Tanks - 1st 30 days (Total Hydrocarbon tpy)	E&P Tanks - Last 30 days (Total Hydrocarbon tpy)	% Change
1	5	22.945	2.809	87.758
2	10	27.116	1.440	94.689
3	11	36.693	1.719	95.315
4	9	29.698	2.106	92.909
5	8	34.580	0.671	98.060
6	6	31.307	1.838	94.129
7	7	60.004	1.651	97.249
8	10	25.484	0.115	99.549
9	3	3.166	1.271	59.855
10	4	6.966	1.000	85.645
11	11	23.240	0.745	96.794
12	8	23.954	0.222	99.073
13	10	18.948	0.272	98.564
14	10	7.020	0.580	91.738
15	11	18.209	0.328	98.199
16	9	31.719	0.671	97.885
17	11	18.739	0.563	96.996
18	6	26.578	0.462	98.262
Averages:	**8.278**	**24.798**	**1.026**	**93.481**

MOGA used the Environmental Protection Agency (EPA) approved E&P Tanks, Version 3 emission estimating software to calculate potential working, standing and breathing emissions based on low pressure oil samples collected according to the California Air Resources Board (CARB) methodology.

The results suggest that during an 8.3-year period, the declining production correlated in a 93% reduction in hydrocarbon emissions.

<u>Production Decline Summary</u>

1. Initial production is significantly higher in the first years following completion. Higher initial production allows for the upfront consideration of long-term cost allocation, planning and implementation of new regulatory requirements such as determination, monitoring, calculations and reporting.

   The expansion of NSPS regulations to include existing and marginal wells does not allow initial capital investment or longevity planning considerations during initial high margin return-on-investment realization. Many marginal wells in Michigan are often 3rd & 4th succession owner wells. The initial high-volume production was realized by previous owners. Each successive sale was based on an updated production formation analysis and projected longevity of the marginal production. Should the EPA decide to include existing and marginal wells with the proposed NSPS regulations, small entity oil and gas producers with marginal wells would not have the associated production to substantiate an initial capital investment combined with ongoing annual cost based on diminishing economic return. This successive ownership paradigm represents the significant majority of oil and gas wells in Michigan. In other words, the expansion of NSPS regulations will disproportionately impact Michigan small business sector leading to dis-investment and loss of opportunity.

2. Production significantly declines within the first 8.5 years. The associated production decline is correlated with a 93% reduction in possible hydrocarbon tank emissions. As a reminder, a 95% reduction from storage tanks is mandated in the 2016 OOOOa source category. Tank emissions would continue to decline until the well reaches a “dead oil” status. “Dead Oil” is an industry term which describes stable oil with minimal work, breathing or flashing emissions.

   <u>Real-life Scenario #1</u>:

   A small entity oil and gas producer in Michigan was subject to Subpart OOOOa regulations for tank emissions. The well and production facility utilized a flare to reduce tank emissions by 95%. The well experienced a rapid production decline and ultimately reached “dead oil” status in a couple years. The well no longer produced enough gas to keep a constant pilot on the flare burning to meet the Subpart OOOOa regulations for the tank battery with minimal working, standing and breathing losses. In order to continue producing the now marginal well while meeting the required Subpart OOOOa *regulations, the small entity purchased and installed a propane tank to keep the pilot light burning. Over time, the cost of conducting semi-annual LDAR surveys, purchasing propane to keep a flare pilot lit and reporting costs for minimal to no tank emissions led the small entity producer to plug the well even though the well would likely produce at a marginal status for many more years.*

3. In the study above, marginal well (≤15 BOEPD) status is achieved around Year 15. The exponential decay curve would indicate continued production indefinitely along the decline curve. Assuming each marginal well experiences a stabilized decline rate of 5-10% annually, the feasible production horizon may be extended for an additional 15 years or more if operations are managed appropriately and costs are minimized. Declining production and maximum resource recovery have a negative correlation as costs to extract the remaining reserves increase, while production declines. During this crucial time in the production paradigm, the addition of costs associated with initial capital investment and ongoing annual monitoring and reporting costs will expedite the plugging and abandonment of wells that would otherwise realize an extended production horizon.

4. The State of Michigan views early plugging and abandonment of wells with remaining production horizons as waste. Part 615 of the state's regulatory framework stipulates the minimization of waste by efficiently managing operational endeavors to achieve maximum resource recovery. Many of the Michigan's small entity producers facilitate this mandate by minimizing operational costs, negotiating production contracts, adjusting operational production schedules and minimizing all costs when available. Michigan's small entity producers require flexibility to meet the State of Michigan's objective to maximize resource recovery. The proposed regulations under Executive Order 13990 would add significant costs to achieve maximum resource recovery and contradict the State of Michigan's mandate by including existing and marginal wells leading to early plugging and abandonment.

Financial Impact Evaluation

As emphasized above, the ability of small business producers to operate wells when production drops below 15 BOEPD is directly tied to cost minimization. The addition of cost from the proposed NSPS will likely accelerate the plugging and abandonment of wells with a viable production horizon.

In addition to the State of Michigan's Part 615 rules and regulations regarding early plugging of viable producing wells discussed above, MOGA views these actions as exceptionally irresponsible, wasteful and impactful to the natural resources of the State of Michigan. A significant one-time financial and environmental cost is required to drill a single well. Plugging wells while oil and natural gas production is still viable will likely exacerbate the need to drill additional wells to meet consumer demand. This would place an unnecessary financial burden and hardship on small entity producers and result in unnecessary stress, pressure and possible impacts on our local Michigan environments. Remember, the small business entities that operate the vasty majority of Michigan's oil and natural gas wells are family-owned businesses that live, work and play in the immediate vicinity of their production assets.

For these reasons, MOGA believes the EPA has not considered the broader economic and environmental impacts the early plugging of wells may have in Michigan. Further, the EPA has not provided a cost benefit analysis showing a valuable correlation between any possible benefits of expanding the NSPS regulations to the economic and environmental costs associated with additional drilling to offset lost production from the early plugging of wells.

In addition to the concerns stated above, MOGA is providing further evaluation and comment regarding the 2016 Model Plant Cost Considerations provided to the participating SERs under the SBAR Panel Process.

One-Time Initial Costs

The EPA's first-year total cost estimates of $2693 per Company with 22 well-sites would appear low. MOGA estimates that requirements stipulated in the 2016 NSPS would likely range from $4,000 to $10,000 for initial implementation.

In Michigan, many small entity's primary focus is the efficient operation, production and maintenance of their wells and facilities. Many of Michigan's small entity producers are unaware of the breadth and scope of the proposed regulation and would likely need to hire a 3rd party consultant to oversee implementation of these proposed regulations. MOGA's cost estimate is based on the necessity to gather, transfer and educate personnel to facilitate the necessary in-depth understanding of each of the 22 well-sites in the EPA's model plant. The variability of these costs can be allocated to specific training, equipment and software purchases and functional knowledge and ability to correctly implement proposed regulation requirements.

Ongoing Annual Costs

Evaluation of the EPA's updated 2016 Model Plant Cost considerations appeared accurate, but the EPA did not consider several factors that many effects the estimated annual cost per well site of $2,368. MOGA would estimate the annual cost per well site to range from $3000 to $6000 for the following reasons:

1. It would appear the EPA is providing an ongoing annual cost estimate based on in-house implementation and completion. As mentioned above, many small producers focus there operational and staffing emphasis on the efficient operation and maintenance of their wells and facilities. Many small producers do not have the operational budget to staff environmental specialists who are educated, trained and certified to properly handle the wide variety of requirements associated with the proposed NSPS regulations. For the reason, MOGA disagrees with the EPA's estimate of $2,638 per well site and offers a more realistic cost range of $3000 to $6000 per well site.

2. The EPA did not consider stand alone initial surveys required for a single well that is either new or has been modified or reconstructed and falls outside of normally schedule monitoring efforts. Single well monitoring using LDAR can range from $2500 to $3500 per site visit for monitoring efforts alone.

3. The EPA assumes a static production regime (fixed production) and constant number of wells (22) as the basis for their ongoing annual estimates. The number of producing wells can be highly variable based on a plethora of variables including seasonal restrictions, formation dynamics, operational agendas to maximize resource recovery, oil and natural prices, land-owner contracts, etc. MOGA would suggest a more variable and fluid assumption of the actual production and operational dynamic when estimating ongoing annual cost estimates.

4. The EPA's assumed annual repair cost per well of $158 shown in the 2016 updated cost considerations is significantly lower than MOGA would expect. On many occasions, the repairs are conducted by 3rd party contractors. A single repair, including parts for a small leak of less than 1 standard cubic feet per day (scf/day) would likely be cost between $500 - $1500.

For both the one-time initial costs and the ongoing annual costs associated with the proposed expansion of NSPS regulations, the EPA should provide cost considerations for both in-house and 3rd party contractors and consultants. This would provide a true and reflective cost based on the wide range of small business criteria and applicability.

<u>Conclusion</u>

The Michigan Oil and Gas Association (MOGA) represents approximately 650 members who engage in the exploration, drilling, production, transportation, processing and storage of crude oil and natural gas within the State of Michigan. A large majority of MOGA's membership meets the definition of a small business entity. These small businesses and their larger counterparts employ an estimated 47,000 Michigan residents.

Many of MOGA's small businesses are responsible for the efficient production and operation of approximately 11,000 natural gas wells and 3,700 crude oil wells within Michigan. MOGA estimates that approximately 94% of these wells meet the definition of marginal or low producing wells.

For the reasons stated above and the potential reciprocal impact to the roughly 47,000 jobs in Michigan, MOGA implores the SBA to continue to advocate for the exemption marginal, low production well and to argue against the expansion of proposed NSPS regulation to existing wells based on the significant economic impact an expanded NSPS regulations would have on a substantial number of small entities within the State of Michigan.

Sincerely,

Eric R. Johnson
MOGA Environmental Chairman

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July 13, 2021
(sent via email)

Ms. Lanelle Wiggins
RFA/SBREFA Team Leader
US EPA – Office of Policy (1803A) – 1200 Penn Ave NW – Washington DC – 20460
202.566.2372

Re: Oil and Natural Gas Sector NSPS

Dear Ms. Wiggins,

On behalf of the Pennsylvania Grade Crude Oil Coalition (PGCC) and Cameron Energy Company, thank you for inviting me to participate as a Small Energy Representative in this NSPS process. PGCC is a trade organization that represents conventional oil and gas interests in Pennsylvania. Conventional wells are shallow (non-shale) vertical wells that produce both oil and natural gas. Pennsylvania boasts the first conventional well, drilled by "Colonel" Edwin Drake, in Titusville in 1859. Today there are over 100,000 conventional oil and gas wells in operation in Pennsylvania. These wells are located in western Pennsylvania, with the southwestern wells producing primarily natural gas and the northwestern wells producing primarily oil. Almost all Pennsylvania conventional wells are low-producing "stripper" wells and are owned by small businesses or sole proprietors. I serve as Secretary of PGCC.

Cameron Energy Company is a family-owned company that employs approximately 40 men and women and has operations in three counties in northwestern Pennsylvania. Cameron supplies natural gas to about 15,000 local households and produces oil which is refined at American Refining Group in Bradford, Pennsylvania, the world's oldest continuously operating refinery. I serve as president of Cameron.

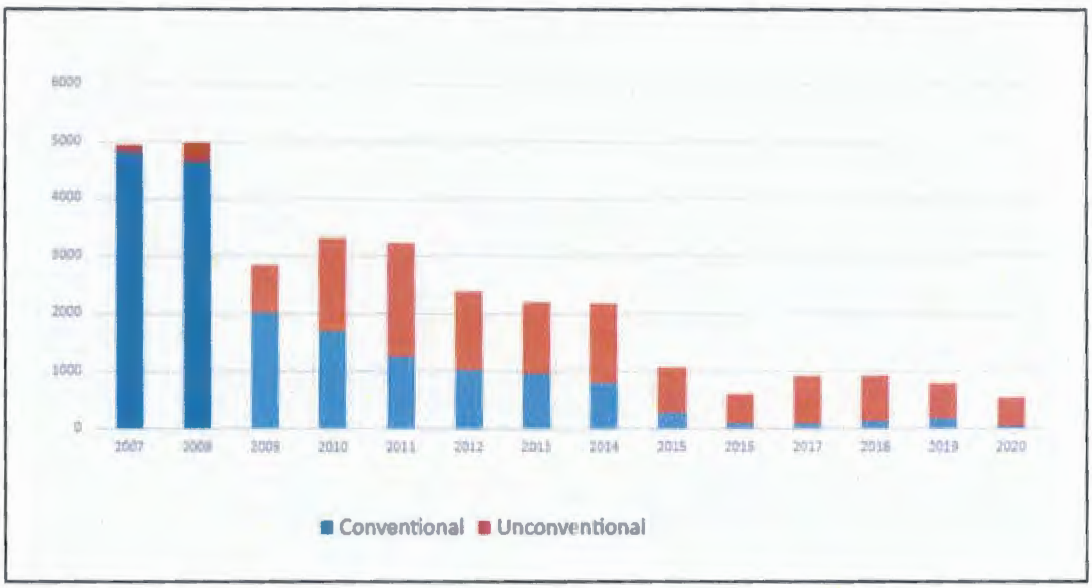
I would like to first provide you with data concerning Pennsylvania's conventional oil and gas wells and the production therefrom. Thereafter I would like to suggest conclusions relative to the NSPS which can be drawn from that data. Finally, I will offer general comments both about process and substance.

The Pennsylvania Department of Environmental Protection (DEP) database recognizes the existence of over 100,000 conventional oil and gas wells in Pennsylvania. However, for the year 2020, operators of Pennsylvania conventional wells submitted oil and gas production data concerning only 79,048 wells. For those 79,048 conventional oil and gas wells the cumulative production for 2020 was as follows:

a) Natural gas: 89,178,071 MCF
b) Oil: 2,824,251 barrels

Utilizing a BOE equivalent of 6000 cubic feet = 1 barrel, the 2020 average annual production for a reported conventional oil and gas well in Pennsylvania is 223 BOE. This average production is less than 1 BOE per day.

A review of the DEP records reveals that most of the wells contained in the conventional well inventory were drilled fifteen or more years ago. Stated in the inverse, the drilling of new conventional wells has collapsed in Pennsylvania over the course of the last fifteen years. Below is a graph showing new well starts, or "spuds", for both conventional and unconventional wells in Pennsylvania.



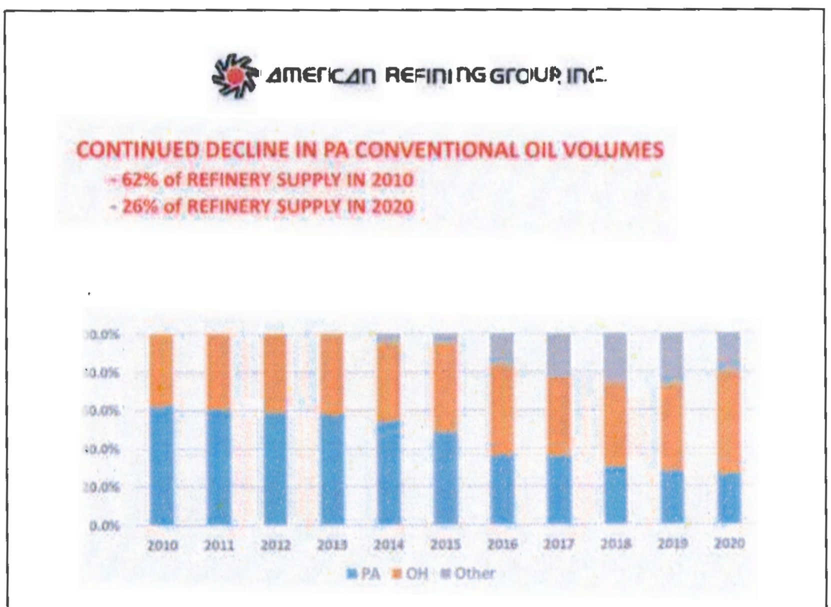
Pennsylvania New Well Spuds

There were 4825 new conventional well spuds in Pennsylvania in 2007. There were 51 new conventional well spuds in 2020, a drop of over 98%.

In order to understand the dynamics of this precipitous drop, PGCC has, over time, polled its members to gather data regarding capital and operating costs and commodity pricing both for conventional "gas" wells (those wells located in southwestern Pennsylvania which produce primarily natural gas) and for conventional "oil" wells (those located in northwestern Pennsylvania which produce primarily oil).

That data reveals it is not economical to drill new conventional oil and gas wells in Pennsylvania. This is a function, first, of the drop in natural gas prices experienced in Pennsylvania as a result of the advent of Pennsylvania's Marcellus and Utica shale development. That shale development impacted natural gas pricing in two ways. The more obvious impact was the drop in NYMEX pricing observed nationwide. Natural gas NYMEX pricing averaged ~$9 during the era immediately preceding Pennsylvania's Marcellus and Utica shale development. In recent years that NYMEX pricing has averaged $2 or less. The less obvious impact was the reversal of the "basis" paid to producers relative to market location. Prior to Pennsylvania's Marcellus and Utica shale development, the United States' natural gas production originated primarily in the south; natural gas consumed in the eastern seaboard region had to be transported from those southern wells to the eastern seaboard. Pennsylvania's proximity to the eastern seaboard rendered Pennsylvania's natural gas more valuable due to lesser transportation costs, and a valuable basis bonus was paid to Pennsylvania's conventional producers over and above the NYMEX price. The vast volumes of Marcellus and Utica natural gas caused a reversal of nationwide pipeline flow and with that reversal the basis bonus became a basis deficit. In 2020 Pennsylvania's conventional producers suffered basis deficits ranging from $.50 to $1.20 per MCF. Therefore, the spreadsheets shown below reflect natural gas pricing that is less than NYMEX pricing.

The inability to drill new conventional wells in Pennsylvania today, as compared to fifteen years ago, is also a function of increased costs. Regulatory changes imposed in Pennsylvania with the advent of the Marcellus and Utica shale well development resulted in new requirements for items such as well casing, cementing and water disposal. These additional costs contribute significantly to the inability of Pennsylvania's conventional industry to bear the cost of new well drilling. That inability to drill new wells is revealed not only in the collapse of new well spuds set forth in the graph above, but also in the reduced oil production flowing to the refineries which receive Pennsylvania's oil as set forth below.



Decline in PA Conventional Oil Received at PA Refinery

As a consequence of the factors cited above, no new conventional well has been drilled in southwestern Pennsylvania (where natural gas would be the primary product) in over five years. The fact of the matter is that under current circumstances a typical Pennsylvania gas well has difficulty bearing the costs of operation let alone the ability to repay the capital costs of new drilling. The data gathered from PGCC members relative to the drilling and operation of a typical Pennsylvania conventional gas well is set forth below:

New Well Base Economics

	Gross Oil	Gross Gas	Net Oil	Net Gas	Oil Price	Gas Price	Net Revenue	Capital Exp.	LOE ($250/w/m)	Water Disposal	Future Revenue	PV(10%)
Initial								300,000			-300,000	-300,000
Yr 1	118	12,450	100	10,582	65.00	1.40	21,317		3,000	360	17,957	17,122
Yr 2	61	9,089	52	7,726	65.00	1.40	14,196		3,000	360	10,836	9,392
Yr 3	41	7,300	35	6,205	65.00	1.40	10,965		3,000	360	7,605	5,993
Yr 4	34	5,963	29	5,068	65.00	1.40	8,959		3,000	360	5,599	4,011
Yr 5	27	4,999	23	4,249	65.00	1.40	7,465		3,000	360	4,105	2,673
Yr 6	30	4,675	25	3,973	65.00	1.40	7,208		3,000	360	3,848	2,278
Yr 7	31	4,356	26	3,703	65.00	1.40	6,873		3,000	360	3,513	1,891
Yr 8	26	4,078	22	3,467	65.00	1.40	6,268		3,000	360	2,908	1,423
Yr 9	21	3,585	18	3,048	65.00	1.40	5,432		3,000	360	2,072	921
Yr 10	31	3,238	26	2,752	65.00	1.40	5,563		3,000	360	2,203	891
Yr 11	31	2,950	26	2,507	65.00	1.40	5,212		3,000	360	1,852	681
Yr 12	28	2,800	24	2,380	65.00	1.40	4,874		3,000	360	1,514	506
Yr 13	27	2,700	23	2,295	65.00	1.40	4,710		3,000	360	1,350	410
Yr 14	25	2,548	21	2,166	65.00	1.40	4,409		3,000	360	1,049	290
Yr 15	23	2,344	19	1,992	65.00	1.40	4,056		3,000	360	696	175
Yr 16	21	2,180	18	1,853	65.00	1.40	3,760		3,000	360	400	91
Yr 17	19	2,049	16	1,742	65.00	1.40	3,511		3,000	360	151	31
Yr 18	18	1,926	15	1,637	65.00	1.40	3,279		3,000	360	-81	-15
Yr. 19	16	1,811	14	1,539	65.00	1.40	3,062		3,000	360	-298	-51
Yr. 20	15	1,702	13	1,447	65.00	1.40	2,860		3,000	360	-500	-78
Yr. 21	14	1,600	12	1,360	65.00	1.40	2,672		3,000	360	-688	-98
Yr. 22	13	1,504	11	1,278	65.00	1.40	2,496		3,000	360	-864	-111
Yr. 23	12	1,414	10	1,202	65.00	1.40	2,332		3,000	360	-1,028	-120
Yr. 24	11	1,329	9	1,130	65.00	1.40	2,179		3,000	360	-1,181	-126
Yr. 25	10	1,249	8	1,062	65.00	1.40	2,037		3,000	360	-1,323	-128
Yr. 26	9	1,174	8	998	65.00	1.40	1,903		3,000	360	-1,457	-128
Yr. 27												
Yr. 28												
Yr. 29												
Yr. 30												
	711	91,012	605	77,360	1,690	36	147,597	300,000	78,000	9,360	-239,763	-252,078

Base Economics for New PA Conventional Gas Well

Recovery of capital costs is not feasible. Moreover, at annual production of less than 2000 MCF (expected to occur at about year 17), the average conventional gas well's net revenue becomes inadequate to cover all operating costs.

The prospect for the average Pennsylvania conventional oil well is slightly better. Indeed, the 51 conventional wells drilled in Pennsylvania in 2020 were drilled in northwestern Pennsylvania with the expectation of oil as the primary product. Cameron Energy Company operates in northwestern Pennsylvania and was the driller of some of those 51 wells. As the president of Cameron, I can advise that the Cameron wells were not drilled in 2020 with the prospect of self-sustaining profitability. Cameron was poised to lay off a significant portion of its staff and to discontinue all drilling in 2020.

However, Cameron was the recipient of Payroll Protection funds in 2020; Cameron utilized those funds to employ its personnel to drill and complete new wells in 2020. Without those PPP funds Cameron would have been unable to carry on any new well operations.

Cameron's position is consistent with the data gathered from PGCC members relative to the drilling and operation of a typical Pennsylvania conventional oil well:

	Gross Oil	Gross Gas	Net Oil	Net Gas	Oil Price	Gas Price	Gross Revenue	Capital Exp.	LOE ($300/w/m)	Water Disposal	Future Revenue	PV(10%)
Initial								125,000		($6/bbl)	-125000	-125000
Yr 1	848	5,236	742	4,581	65.00	1.40	54,640		3,600	10,175	40,865	38,963
Yr 2	534	3,619	468	3,167	65.00	1.40	34,825		3,600	4,809	26,416	22,897
Yr 3	294	2,255	257	1,973	65.00	1.40	19,488		3,600	2,647	13,242	10,434
Yr 4	180	1,511	158	1,322	65.00	1.40	12,089		3,600	1,620	6,869	4,920
Yr 5	144	1,239	126	1,084	65.00	1.40	9,708		3,600	1,296	4,812	3,134
Yr 6	122	1,053	107	922	65.00	1.40	8,252		3,600	1,102	3,550	2,102
Yr 7	107	927	94	811	65.00	1.40	7,227		3,600	964	2,663	1,433
Yr 8	96	834	84	730	65.00	1.40	6,504		3,600	868	2,037	996
Yr 9	87	767	76	671	65.00	1.40	5,874		3,600	781	1,493	664
Yr 10	78	714	68	624	65.00	1.40	5,315		3,600	703	1,012	409
Yr 11	70	671	61	587	65.00	1.40	4,818		3,600	632	586	215
Yr 12	63	631	55	552	65.00	1.40	4,369		3,600	569	200	67
Yr 13	57	593	50	519	65.00	1.40	3,963		3,600	512	-149	-45
Yr 14	51	557	45	488	65.00	1.40	3,596		3,600	461	-465	-128
Yr 15	46	524	40	458	65.00	1.40	3,264		3,600	415	-751	-189
Yr 16	41	492	36	431	65.00	1.40	2,963		3,600	373	-1,010	-231
Yr 17	37	463	33	405	65.00	1.40	2,691		3,600	336	-1,245	-258
Yr 18	34	435	29	381	65.00	1.40	2,444		3,600	302	-1,458	-275
Yr. 19	30	409	26	358	65.00	1.40	2,221		3,600	272	-1,651	-283
Yr. 20	27	384	24	336	65.00	1.40	2,019		3,600	245	-1,826	-285
Yr. 21	25	361	21	316	65.00	1.40	1,836		3,600	221	-1,984	-281
	2,973	**23,676**	**2,602**	**20,717**			**198,107**	**125,000**	**75,600**	**29,303**	**-31,796**	**-40,740**

Base Economics for Pennsylvania Conventional Oil Well

Recovery of capital costs, while more likely with the conventional oil well, is still infeasible in the face of the operating costs. And, like the average gas well, the average oil well's net revenue becomes inadequate to cover all operating costs at about year 13, even if we ignore the matter of the repayment of the capital costs.

On behalf of PGCC and Cameron Energy Company, I recommend that low producing wells (15 BOE per day or less) be exempt from the NSPS rules under consideration. New conventional wells in Pennsylvania do not produce sufficient revenue to bear the inspection, testing, paperwork and other costs associated with the OOOOa requirements. Moreover, the amount of emissions which could theoretically be associated with Pennsylvania's new conventional wells is very low. The sheer small volume of natural gas produced by Pennsylvania's new conventional wells indicates that the cost of the regulations is not worth any potential benefit. Finally, we should take note of the natural incentive inherent in the data set forth above. The profitability margins associated with a Pennsylvania conventional oil and gas well are razor thin even under economic conditions superior to those which pertain today. Therefore, the Pennsylvania conventional oil and gas operator has great natural incentive to insure that no natural gas product is lost through the types of emissions which the regulatory package is designed to prevent.

I would like to close by making general comments about both the process associated with, and certain substantive matters concerning, the new rules under consideration. Relative to the process I note that our initial ZOOM conference with the EPA was conducted June 29, 2021. The EPA required these comments to be submitted by today which, obviously, is the mere time span of two weeks. The July 4th holiday fell within that span of two weeks. PGCC's legal committee meets monthly, with its next meeting scheduled for July 15, 2021. It was therefore impossible to take this matter before the committee and to collect considered comments, to gather all meaningful data, and to respond in a comprehensive fashion. I collected the graphs and other data provided above, from other documents that were previously assembled by PGCC for other purposes.

From a substantive perspective there are undoubtedly many factual matters that should be considered and commented upon. For example, many tank facilities utilized in Pennsylvania's conventional oil and gas operations are located in very rural areas, many thousands of feet or miles distant from electrical service. Will this have an impact upon costs? Many conventional wells are operated only seasonally due to snow or other conditions. Will this have an impact on costs? During the July 29th ZOOM conference, I posed these questions: *1) In providing comments should we assume that the 2020 Technical Rule exempting low production well sites will remain in place, meaning that low producing wells (and associated equipment at those well sites) will not be subject to the NSPS?*
2) Existing storage vessels and other equipment currently in place will likely be connected to new source facilities--how should we frame comments and data—should the comments and data contemplate the existing facilities? The answers are not known, in great part, due to the haste at which this process is unfolding.

PGCC and Cameron Energy would like to provide input as to specific costs and other relevant facts. But the prevailing speed and uncertainty of what is being proffered make such input impossible.

Sincerely,

Arthur Stewart
Camelot1@atlanticbb.net

JOINT COMMENTS

OF

THE AMERICAN PUBLIC GAS ASSOCIATION,
CITY OF LAS CRUCES UTILITIES/GAS, MIDDLE TENNESSEE NATURAL GAS UTILITY DISTRICT, PENSACOLA ENERGY, AND UNITIL CORPORATION

REGARDING US EPA OIL AND NATURAL GAS SECTOR NEW SOURCE PERFORMANCE STANDARDS

SMALL ENTITY REPRESENTATIVE PRE-PANEL OUTREACH

July 13, 2021

The American Public Gas Association (APGA), City of Las Cruces Utilities/Gas (Las Cruces), Middle Tennessee Natural Gas Utility District (MTNUD), Pensacola Energy, City of Pensacola (Pensacola Energy), and Unitil Corporation (Unitil) respectfully submit these joint comments in response to the U.S. Environmental Protection Agency (EPA) Small Entity Representative Pre-Panel Outreach virtual meeting on June 29, 2021 regarding EPA's plans for developing proposed revisions to the oil and natural gas sector new source performance standards (NSPS) in 40 C.F.R. Part 60, Subparts OOOO and OOOOa.

Qualifications as Small Entity Representatives

APGA is the not-for-profit trade organization representing America's publicly owned natural gas local distribution companies. On behalf of their membership, APGA engages on issues pertaining to the safety, reliability, operational efficiency, and regulatory environment in which publicly and community owned gas systems operate. Of APGA's 739 current member systems, 734 qualify as small business entities under 13 CFR §121.201 NAICS Code 221210 because they employ less than 1,000 individuals. Erin Kurilla, APGA Vice President, Operations and Safety, has nominated herself as a Small Entity Representative for APGA.

The City of Las Cruces in New Mexico owns Las Cruces Utilities/Gas, which is a municipal gas utility operating a local natural gas distribution system with 65 employees serving 43,000 customers. Las Cruces Utilities qualifies as a small entity natural gas distribution utility (NAICS Code 221210) because it has less than 1,000 employees. Lucio M. Garcia, P.E., CEM Deputy Director of Las Cruces Utilities/Gas, has nominated himself as a Small Entity Representative (SER) for Las Cruces Utilities/Gas. The City of Las Cruces is a joint member of both APGA and the American Gas Association (AGA). Mr. Garcia has also requested that Pamela A. Lacey, Chief Regulatory Counsel for the American Gas Association (AGA) be present in meetings to assist him as an SER.

Middle Tennessee Natural Gas Utility District is a publicly owned natural gas distribution company with 135 employees and 66,000 customers. MTNGUD qualifies as a small entity natural gas distribution utility (NAICS Code 221210) because it has less than 1,000 employees. Matthew C. Stennett, P.E., Vice President – Engineering of MTNUD has nominated himself as a Small Entity Representative (SER) for MTNGUD. Mr. Stennett has also requested that Erin Kurilla, Vice President, Operations and Pipeline Safety for APGA be present in meetings to assist him as an SER.

Pensacola Energy, a publicly owned utility company in the city of Pensacola, FL, has an average annual employment of 122 individuals and serves approximately 44,000 customers with 1,700 miles of pipeline. Pensacola Energy qualifies as a small entity natural gas distribution utility (NAICS Code 221210) because it has less than 1,000 employees. Diane Moore, Gas Distribution Engineer, has nominated herself as a Small Entity Representative (SER) for Pensacola Energy. Diane Moore has also requested that Erin Kurilla, Vice President, Operations and Pipeline Safety for APGA be present in meetings to assist her as an SER.

Unitil is an investor-owned electric and gas utility company with two electric distribution subsidiaries, three local natural gas distribution subsidiaries, and one *interstate* natural gas transmission pipeline subsidiary that operates in Massachusetts, Maine and New Hampshire. Unitil qualifies as a small entity for its electric and gas distribution utility operations (under NAICS Codes 221122 and 221210) with 510 employees as of December 31, 2020. Unitil also qualifies as a small entity for its 75-mile natural gas *interstate* pipeline operations (NAICS Code 486210), which had less than $30 million in annual receipts from natural gas transmission pipeline business in the last fiscal year. Thomas J. Murphy, Unitil’s Manager, Environmental, Health & Safety, has nominated himself as a Small Entity Representative (SER) for Unitil on behalf of its gas distribution utilities and its interstate transmission pipeline subsidiary. Mr. Murphy has also requested that Pamela A. Lacey, AGA Chief Regulatory Counsel be present in meetings to assist him as an SER.

<u>Small Entity Impacts Depend on Potential Scope of Proposed Rule</u>

Impacts on our small entity operations depend on the scope of EPA’s plans for the proposed revisions to the volatile organic compound (VOC) and methane NSPS under 40 C.F.R. Part 60 Subparts OOOO and OOOOa as adopted in the final rule published June 3, 2016 and recently reinstated by President Biden's signing of the Congressional Review Act Resolution. If EPA is not considering any changes to the 2016 final rule exemption of natural gas utility intra-state distribution, transmission pipeline, storage or LNG peak shaving operations inside and including the local distribution utility custody transfer station, then our gas utility operations would not be affected. If EPA is not considering changing the 2016 final rule's requirements for interstate natural gas transmission pipelines, then Unitil's interstate natural gas transmission pipeline operations would not be affected. However, if EPA does plan to consider any such changes, then we will need an opportunity to provide information about how those proposals could impact our small entity operations. EPA would also need to develop a robust administrative record to support any such additional requirements, which could be challenging given the very ambitious timeframe for this rulemaking.

At present, under the 2016 regulations recently reinstated by Congressional Review Act Resolution signed into law by President Biden, neither set of regulations apply to operations inside of and including the natural gas utility custody transfer station. Effectively, that means that all natural gas utility company operations – including <u>intra-state</u> natural gas distribution systems, <u>intra-state</u> natural gas transmission pipelines, and natural gas storage facilities connected to <u>intra-state</u> natural gas transmission pipelines -- are exempt from the existing methane NSPS. They are also excluded from the VOC NSPS because of the minimal VOCs contained in pipeline quality natural gas downstream of processing.

It should be understood that the terms "transmission" and "distribution" are defined by the Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) based on the operating pressure and primary function of the pipeline, as set forth in PHMSA's pipeline safety regulations under 40 C.F.R. Part 192. Gas utilities operate both transmission and distribution pressure level natural gas pipelines within a single state system that is subject to economic regulation by the applicable state utility commission. The intra-state utility transmission pipelines tend to be operated at a lower pressure than the interstate pipelines and either have smaller compression stations or none. Higher pressure, long-distance interstate transmission pipelines are economically regulated by the Federal Energy Regulatory Commission (FERC). The reinstated 2016 NSPS final rule imposes leak detection and repair (LDAR) requirements for FERC-regulated interstate transmission pipeline *compressor stations*, but it does not impose requirements on interstate pipelines or on gas utility operations.

EPA under President Obama decided to exclude natural gas utility operations from the methane NSPS because of the remarkable progress gas utilities have made since 1990 in reducing emissions, as demonstrated by EPA's annual Inventory of U.S. Greenhouse Gas Emissions and Sinks. AGA's analysis of the most recent EPA GHG Inventory released in April 2021 shows for example that gas utilities reduced methane emissions from distribution systems nationwide by 69% between 1990 and 2019, and that in 2019 the remaining methane emissions from distribution was just 0.1 percent (one tenth of one percent) of annual natural gas production.[1] Gas utilities achieved these reductions by modernizing their systems, adopting best management practices (BMPs) shared through EPA's voluntary Natural Gas STAR and Methane Challenge Programs as well as APGA and AGA initiatives, and -- with approval from state utility commissions -- accelerating the pace for replacing leak-prone pipe (cast iron, cathodically unprotected steel, and vintage plastic pipe) with modern cathodically protected steel and medium or high density polyethylene (PE) plastic pipe.[2] These initiatives include BMPs for reducing methane from intra-state and interstate transmission pipelines and storage facilities.[3]

The current exclusion of gas utility operations can be found in the definition of the "source category" for the NSPS, which excludes operations inside and including the "l*ocal distribution company (LDC) custody transfer station."* That term is further defined as follows the 2016 final rule published at 81 Fed. Reg. 35824, 35933 (June 3, 2016) –

> ***Custody transfer*** means the transfer of crude oil or natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.
>
> ***Local distribution company (LDC) custody transfer station*** means a metering station where the LDC receives natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC's intrastate transmission or distribution lines.

In addition, EPA's companion "Response to Comments" document clearly says they are exempt. Importantly, the agency accepted AGA's comment requesting EPA to replace the vague term "city gate" with our defined term, LDC custody transfer station, in order to

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[1] See Understanding Updates to the EPA Inventory of Greenhouse Gas Emissions from Natural Gas Systems (May 17, 2021) at https://www.aga.org/research/reports/epa-updates-to-inventory-ghg/ .

[2] See EPA Natural Gas STAR and Methane Challenge Programs at https://www.epa.gov/natural-gas-star-program/methane-challenge-program.

[3] See https://www.epa.gov/natural-gas-star-program/methane-challenge-commitment-options as well as Transmission & Storage BMPs at https://www.epa.gov/natural-gas-star-program/natural-gas-star-program-implementation.

more clearly delineate what sources are exempt from the new methane standards.[4] The agency explained:

> *"The proposed rule … used the term "city gate" to delineate the boundary of the natural gas industry in this listed source category as not extending beyond the city gate. We defined "city gate" in the proposed rule as 'the delivery point at which natural gas is transferred from a transmission pipeline to the local gas utility.' The proposal was based on our understanding that the local gas utilities are the beginning of the distribution system that delivers natural gas to customers (which is not a part of the listed source category). However, the commenter argues that the term 'city gate' has various meanings in the industry and the use of the term in the proposed rule creates confusion. In light of the various uses and understanding of the term 'city gate,' we agree that the term may result in some level of confusion.* ***In order to avoid such confusion, in the final rule we have removed the term 'city gate' and replaced it with 'local distribution company (LDC) custody transfer station.'***
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> *[p. 1-14]* ***EPA agrees … that there are natural gas transmission lines and compressors beyond the LDC custody transfer station. They are part of the gas distribution system that delivers gas to customers, which is not covered by the listing of this source category****."*[5]

Further, EPA also confirms in its Response to Comments document that the rule does not cover the following *if located downstream of the LDC custody transfer station*: (1) underground storage facilities; (2) LNG peak shaving storage facilities; (3) propane peak shaving facilities; (4) intra-state transmission lines; and (5) compressors and compressor stations.[6]

Conclusion

If EPA is considering changes to this gas utility exemption or to the scope of requirements for interstate pipeline operations, then we will need to know what those possible changes would be so that we can provide information about how that would impact our small entity operations.

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[4] EPA Response to Comments on Proposed Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources (June 2016) (Response to Comments), Chapter 15 Miscellaneous, pp. 15-279-280 (response to AGA comment on "city gate," substituted defined term "LDC custody transfer station" as dividing line for exempted natural gas LDC sources).

[5] Id, emphasis added.

[6] Response to Comments, Chapter 4 Fugitives, p. 4-385.

We appreciate the opportunity to comment. If you have any questions, please contact Erin Kurilla ekurilla@apga.org or Pam Lacey placey@aga.org.

Respectfully submitted,

Date: July 13, 2021

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July 13, 2021

Ms. Lanelle Wiggins
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Re: SER Response for the Small Business Advocacy Review (SBAR) Panel Process regarding Executive Order 13990

Dear Ms. Wiggins:

Fore Energy Partners, Inc. (FEPI) is submitting this response to Environment Protection Agency (EPA) for the Small Entity Representatives (SER) for EPA's Rulemaking "Oil and Natural Gas Sector New Source Performance Standards" Outreach Meetings. FEPI is representing the small business sector of oil and natural gas production for the state of Michigan. These small producers, along with major companies, are regulated by numerous state and federal agencies to oversee the reserves produced, the brine water disposals, the crude oil and natural gas sold, the air permit limitations for fuel combustion, flaring of stranded natural gas and emission levels. Not only are these agencies monitoring and managing these aspects of public health, but there are contractual obligations to purchasers of the commodities, agreements with landowners, public reviews with townships and counties that require testing and reports.

This correspondence will not address the initial investigations for site selection, contract stipulations, engineering, drilling, completion, facility installations, original permitting, or any activities required to begin production. The focus will be centered around the initial production, productive life of the well, operations of the well equipment, daily, monthly and yearly report generations and the costs associated with gathering this information.

Conclusions

1) Recovery of the last remaining reserves in existing reservoirs requires the best technology and prudence to remain profitable for today's marginal well producers.
2) Regulations need to match the difficulties in recovering these last remaining reserves with the environmental conditions that are so important to today's living.
3) Regulations from different agencies of state and federal government need to know the implications their rules' effect on sister agency's decisions.
4) Studies are being conducted to support marginal well operations as lower emitters. These studies are funded by states and federal agencies, like the Department of Energy (DOE).

5) Permits that no longer impact the environmental quality or are below a standard outlined in the regulation should be declared as negative declaration and not require reports to specific agencies. Monitoring would be internal documents for the operator.
6) Owners/operators of marginal well producing companies live and work in the communities where production exists. We want the best for their families, so maintaining well managed and operating companies accomplishes these goals.

Production Life

The life of any crude oil or natural gas wells begins with initial completion. This is the high point in a well's existence because the most production will be generated at the beginning. Unless there are multiple horizons or formations that have future potential to produce, could there be an influx of production similar to the initial completion. Most Michigan wells have a single formation so a second surge in production is unlikely. The decline curve found at the conclusion of this letter demonstrates the life cycle for a typical Michigan well. Costs during the early years, except for capital, are at the lowest level proportionately because production does not require artificial lift, the facility and wellhead equipment is new, utility and maintenance charges are minimal. As the well matures, then artificial lift is implemented, utility charges increase (unless onsite fuel provides the needed energy to operate), chemical usage is implemented to improve fluid flow and equipment begins to be replaced due to wear and tear.

Reservoir pressure supplies the needed energy to produce the commodities many thousands of feet below the surface. The equipment at the surface is designed to meet or exceed the safety requirements for this pressure throughout the life of the well. Containing the pressure within the piping and process equipment protects the environment and allow transport of the fluids to desired storage, sales points or controlled consumption. Again, the largest fluid flow through the wellhead and facility is at initial completion. Throughout the life cycle, pressure decrease, production declines and artificial lifting becomes more complicated. This decline requires alterations to the facility and wellhead to meet the loss of pressure. These alterations require production practices to also change again to keep the commodities internal to the equipment thus preventing any emissions to occur.

Regulatory Obligations

Compliance with either Subpart OOOO or OOOO(a) of the Clean Air Act (CAA) has become a troublesome accomplishment because of the ever-changing conditions placed within the rules. Under Subpart OOOO, marginal well producers had means of being able to reduce regulatory obligation as wells become less and less productive. Production history for the wells demonstrated that lower production and flowing pressures were not emitting greater quantities of volatile organic compounds (VOC's) but were in fact following the decline trend of the well with lower and lower potentials to emit. This trend moves marginal well (or stripper wells) status to a negative declaration because the quantities of VOC are so minute compared to the emission levels in the general area of the production. Subpart OOOO(a) removes marginal well status from the rule and burdens the producers with detailed and comprehensive report filings that do nothing to summarize very low VOC contributions.

The compliance with state regulations for oil and natural gas production as managed with Part 615. This rule has long been an acceptable standard for oversight of the industry. Producers have few if any problems complying the rule and its abilities to allow well-managed production to be achieved at all levels. Rule 615 promotes ultimate recovery from the production formations so the maximum recovery takes place no matter the timeframe.

Competition for complying with multiple agencies leads to shutting down operations, purchasing needless equipment which poorly operates, capital expenditures that cannot be recovered from the remaining reservices or overlooking compliance because rules may negate equipment use.

Additional Obligations

Mineral ownership has a heavy burden for producing companies. Dependent upon the negotiated contracts, the royalty amounts range from 12.5% to 20%. These amounts can reduce the price on a barrel of crude oil by $7.00/bbl to $15.00/bbl and natural gas by 0.25/MCF. Contracts with landowners for egress and entrance to the property along with leases for facility construction add to the monthly operating expenses.

Adding to these charges, the obligation of severance taxes can amount to 5%, reducing the market value of crude by $3.00 per barrel. Another item of interest is the sellable condition of the hydrocarbons produced through the wellhead. Typically these fluids are poorer in quality than West Texas Intermediate. The discount for this quality ranges from $3.00 to $4.00/bbl. One more item is transportation. Most crude oil is transported by truck rather than pipeline, so charges to get the product to market are $4.00 to $6.00/bbl.

Finally, the plugging and abandonment of the well presently costs between $45,000 and $60,000 unless there is casing collapse or stuck tools in the hole. There maybe separate charges for environmental impact.

Financial Assessment

Estimations for typical marginal wells in Michigan have this type of calculations.

Remaining reserves – 1,200 BO
Decline rate – 5%
Production life – 15 years
Initial Production Rate – 10 BOPD
Final Production Rate – 2 BOPD
Commodity Price (constant) - $60.00/bbl
Potential Gross Revenue – 1,200 BO x $60.00/bbl = $72,000
Mineral Owner payment (12.5% royalty) = $72,000 x 0.125 = $9,000
Severance taxes – 1,200 BO x $3.00/bbl = $3,600
Deduction for crude quality - $3.00/bbl x 1,200 BO = $3,600
Transportation charges - $4.00/bbl x 1,200 BO = $4,800

Potential Net Revenue - $51,000

Some of the charges may be eliminated by negotiating better transportation fees, crude oil quality blended with more acceptable cleaner crude and commodity prices may change.

With the advent of tighter controls on fugitive emission releases and compliance monitoring for air quality issues, annual fees for report submittal could increase because of site visits, data collection, lease detection and repair (LDAR), equipment replacements and well workovers. The increase could result in a few thousand dollars per year. Over the life of the well, the remaining net revenue for the well would approach zero.

Fore Energy Partners, Inc. appreciates this opportunity to present a better understanding of the marginal well producers' industry for the betterment of authoring regulations that match the production of oil and natural gas in the state of Michigan and in our country.

Sincerely,

J. Scott Huber
Partner
Fore Energy Partners, Inc.
Mt. Pleasant, Michigan

Michigan Low Production Type Curve