Appendix B: Written Comments Submitted by Small Entity Representatives

Appendix B2. Written Comments from SERs following the July29, 2021 Panel Outreach Meeting

August 12, 2021

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Ms. Wiggins:

Thank you for the opportunity to provide final comments to the Small Business Advocacy Review Panel - Oil and Natural Gas Sector New Source Performance Standards. We have expressed before, but it is worth reiterating that our association sincerely appreciates EPA's work to listen to small businesses and small entity representatives to incorporate their concerns into the rulemaking process moving forward. As a representative of small businesses, the Texas Alliance of Energy Producers has an obligation to advocate for our clients when we see potentially negative regulatory burdens will make small businesses less competitive to larger competitors or worse make operations impossible due to regulatory requirements sized to larger companies. We fear without clear exception and a bifurcation of regulatory requirements for small operations, small business will be harmed.

We represent 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. In fact, 100% of the operators represented on our board of directors qualify as small businesses under the Small Business Administration's size standards guidelines. There are only a handful of oil and gas producers in Texas that would not be qualified as small businesses under those employee count size standards. In terms of the operators represented in our membership, easily over 95% would be considered small businesses.

Even those can be misleading, however. The SBA size standards suggest that an oil and gas producing company with fewer than 1,250 employees (and yes, there are revenue standards as well) is considered a small business under that definition. Of the top 30 crude oil and natural gas producers in Texas, fewer than half have more than 1,250 employees. The next tier of operating companies, the larger publicly traded independents and other sizable independent producers, may total another 20-30 operators. The number of employees in these companies may total anywhere from 200 to 800 or so. In Texas, however, there are literally hundreds of operators outside of these groups who are producing some volume of crude oil and natural gas in the state. It would be difficult to argue that the smallest of small oil and gas operators, who comprise the majority of Texas operators (in number, not in production volume) would not be significantly affected by the implementation of more costly and burdensome methane regulations. A rigorous examination of these potentially negative economic impacts through the SER/SBAR process is warranted *prior to* the drafting of new methane rules.

That also points to the potential need to establish subcategories of sources that would include size and/or production volume/volume per well/well site distinctions. Marginal operators and operators of low volume wells and well sites stand to be exponentially more greatly affected by the implementation of one-size-fits-all regulations. Indeed, such a process would clearly disadvantage smaller operators relative to larger operators who can more easily absorb the costs and other burdens involved. As to marginal/low volume wells, no matter who operates them (large or small producers) those wells are much more likely to become uneconomic and cease to operate with additional imposed costs of continuing to operate those wells.

And though it is not the purpose of this process to consider such outcomes, costly and burdensome methane regulations make it more likely that low volume wells may be ultimately orphaned or abandoned as the cost of operating them goes up.

Reliable data on emissions from marginal/low volume wells and well sites would be highly useful in informing the proper ways to deal with these issues in the writing and implementation of the new methane rule. Sufficiently reliable data does not seem to exist but may become clearer with the release of the DOE study later this year, referenced below, to assist in quantifying emissions from low volume wells. It would be advisable to wait on that data and other information before moving forward with regulations that will affect the operators of those wells.

Cost and Regulatory Burden

The cost estimates provided by EPA were helpful to guide discussions with Alliance members. Optical gas imaging (OGI) requirements place unique burdens on small businesses, different than larger ones. EPA has repeatedly heard in-house training and specialization on this is the best way to control cost, but that option is not always available to small businesses. The prospect for contract or outsourcing this requirement will place undue burden on small operators and cost estimates should reflect regional variability and rural workforce considerations that will show dramatic differences in price per service. The Alliance surveyed our membership and suspect $2,368 per facility to be low. Many of the comments from members reflect they lack the adequate staff and resources to meet this new requirement should it be implemented for all facilities. "This expense combined with other monitoring activities would make some of our leases uneconomic," said one member. Another said, "We have low volume wells. This would be cost prohibitive." For low production wells there is a significant concern that cost cannot be absorbed due to price constraints and the inability to absorb new operational requirements. This will result in a heightened negative impact to small businesses.

We asked if this contracted workforce was available across Texas to perform this new requirement and 74% of respondents said 'No'. There were a variety of reasons for this which included lack of workforce and training with many objections raised on the need for this at smaller operations or marginal production facilities. 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.

Environmental Protection

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 Small Business Advocacy Review Panel - Oil and Natural Gas Sector New Source Performance Standards.

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Lanelle Wiggins <Wiggins.Lanelle@epa.gov> August 12, 2021
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Re: Second round of Pre-Panel Comments on Oil & Natural Gas Sector New Source Performance Standards

Dear Lanelle,

Again, thank you and the SBAR Panel for the opportunity to send additional comments on potential changes to the New Source Performance Standards for the Oil & Natural Gas Sector. After reviewing the slides presented at the two resent zoom meetings, including posed questions, I have information in four areas regarding typical low volume wells that I feel will help the Panel with recommendations. Again, I am commenting from the perspective of a small operator similar in size to hundreds of other small operators in Kentucky with wells in both the Appalachian Basin and Illinois Basin areas of the State. Wells we currently operate were drilled as far back as the 1980's, and exhibit production decline rates such that they could be viable producers with a life of 50 to 60 years, depending on natural gas prices and operating costs. There are many examples of wells 100 plus year old still economically producing gas in eastern Kentucky. They are capable of producing that long because of very low operating costs.

My concern is the additional costs associated with Quad O and Quad Oa compliance, especially when the prescribed methods would do little to actually reduce overall methane emissions. Simplified and cheaper methods need to be identified and adopted. Current compliance costs applied to legacy wells and fields like we have, or any new wells we might drill, change their economic viability. Legacy fields would become uneconomical to continue to produce and drilling new wells would be difficult to economically justify.

Characteristics of a typical east Kentucky gas or oil well is a vertical hole of depths between 800 feet and 4,000 feet, depending on the target formation, that has been fracked using fluid and sand, and often energized with nitrogen, or even fracked with just nitrogen. Even though our conventional low volume low pressure wells have been fracked for decades (since the 1960's) the "frack job" is not of the scale of those jobs done on deeper higher pressure wells in other basins or even Marcellus Shale wells in the northern Appalachian Basin. Our wells are fracked using tens of thousands of gallons of water where Marcellus wells use Millions of gallons of water. Producing formations in the Appalachian Basin of Kentucky have such low pressures, typically with less than a 600 psi shut in pressure, and even less from shallower formations (350 psi at 2,500 feet), that the fluid used to frack the wells overcomes the reservoir pressures and kills the wells. The fracked wells then require pumping or "swabbing" to remove the fluid so that the wells will produce. Only with energized fracks will the wells possibly flow back, bringing some of the frack fluid with it. There is very little that will burn during the “flow back”. No separator is needed even though one is required. In the cases during completion or rework of low volume low pressure wells, when it might be feasible to flare safely, the requirement of a flare stack should be waived. The cost of flare stacks are hard to justify for the small reduction of methane emissions during the short periods and small volumes that might be flared over a pit. Flare stacks add little value other than to burn the propane necessary to have a pilot flame available. It is only after the majority of the frack fluid is removed will any significant amount of gas or oil be present.

Swabbing is done in our area with a small truck mounted rig that is moved over the wells when needed. Our typical gas producing formations have little to no associated fluid production. But well construction often includes a string of tubing run to the bottom of the well in order for any fluid buildup over time to be removed by pumping or swabbing. We operate some wells that have never been swabbed and others that need to be swabbed once every couple of years. Swabbing is usually done in a matter of hours and the fluid removed is trucked off location. Little gas is vented during the process, and what is vented would almost be impossible to flare due to the typical size of our locations (less than an acre), and usual proximity to forested lands. To my knowledge there are no other ways to remove fluid from the low pressure wells economically with less emissions. Plunger lift systems don’t work in our area because we don’t have enough volume or pressure associated with our wells to lift much of a column of fluid up a string of tubing on top of a plunger.

A typical Appalachian Basin gas gathering system is constructed using plastic pipe, which comes in 500 foot rolls and are fused together and buried. The maximum pressure on the plastic pipe is about 100 psi. Components and equipment at the well location usually include less than two dozen 1” and 2” valves (total wellhead component counts are less than 60 including nipples), a drip tank, which is a small pressure vessel designed to collect any moisture that might be in the gas due to condensation, an orifice meter tube and its recording device, a pressure regulator protecting the downstream plastic piping (in case the gathering system should be shut in for any length of time and the well pressure up to a level that might damage any plastic piping); and possibly a tank to collect any fluid swabbed from downhole or blown from the drip tank. These types of components and equipment, as well as any booster compressors or other equipment necessary to produce a low pressure well, should not make a well location an “effected facility”.

Gathering system pressures are never much above 100 psi, and with legacy wells like we and many small operators have, the flowing pressures are 25 psi or less. Any thread leak that should develop on a low pressure wellhead is of little consequence in the scope of controlling fugitive methane emissions. Most leaks, noticed because of the sound it makes or smell of natural gas, can be corrected by the well tender on his bi-monthly or monthly visit to the wellsite to change charts on the orifice meter, with just a pipe wrench. Expensive optical gas imaging equipment, elusive in our part of the world, is not justifiable to find and correct the occasional thread leak on a low pressure stripper well.

Often on the other end of the gas gathering systems operated by many small operators is a compressor used to deliver produced gas into a sales pipeline. We have several companies in eastern Kentucky that operate larger gathering or transmission pipeline systems that are the market for the gas produced by the small operators. The compressor is required to deliver the low pressure gas from the small operator’s gathering system into the higher pressures of the “sales” pipeline. These “centralized” production facilities of the small operators usually contain a compressor run by either an electric motor or natural gas fired engine, a storage tank (usually less than 100 bbl) to store water from the gas that might drop out in separators before going through the compressor, and occasionally a dehydrating system. Both the motor and the engines used are typically less than 100 horse power (a few larger gathering systems may have compressor engines with up to 250 hp). Dehydration of the field gas (if required) to make it “pipeline quality” for the larger gathering systems might entail the use of a tri ethylene glycol system. The smaller gathering systems tend to use a desiccant dehydrating system. Locations for these types of production facilities generally cover much less than an acre, and are located so there is minimal distance to the pipeline into which they are discharging, usually less than a mile and are often only a few hundred feet away.

Few new “central” production facilities have been built over the past ten years in east Kentucky due to the depressed markets for natural gas. The few newly drilled wells have been located in areas where existing gathering systems can be utilized. Of more interest has been the need to down size existing facilities to be more efficient with declining produced volumes. The exemption from Quad Oa for modified compressors where they are downsized needs to continue. It is our hope that natural gas prices will move back to levels where the small operator in Kentucky can get back to what they do best, explore for and produce natural gas and oil.

Quad Oa requirements associated with a new compressor could prevent a small operator from developing new gas fields. As with wells, fugitive emission surveys of compressor stations using optical gas imaging is a service not readily available in our area. The costs to bring the equipment necessary in from other areas of the country four times a year are prohibitive and detract from any further gas field development. As with wellheads, thread leaks or vented gas associated with the brief blowing of a drip tank at a production facility, are not significant emission sources, and when found by sight, sound, or smell, can easily be corrected with a pipe wrench. Additionally, the current requirement of replacing rod packing of a reciprocating compressor every 36 months is also a burden to the small operator. Unnecessary maintenance and down time hurts revenue for no real reason. Rod packing in compressors that run at relatively low pressures and RPM can last well over 60 months. Production facilities in our part of the world are not “manned”, but visited by the facility operator at least weekly, if not daily. Significant leaks don’t go unnoticed for any length of time.

Most wells in Kentucky begin their production life as a stripper well (15 barrels of oil or 90 Mcf per day). The real value to oil or gas wells drilled in Kentucky is their longevity. The rare atypical oil or gas well in Kentucky might have initial production volumes of what is considered more than a stripper well, but typical of Appalachian Basin reservoirs, (low permeability and low pressure) that production rate declines rapidly. During the higher initial production rates, those few wells can afford Quad Oa compliance of fugitive emission surveys using optical gas imaging. But, once production rates drop to and below what is considered “stripper” levels, the costs become a detriment to continued production. Many years, if not decades of probable continued production life, could be cut short. The higher production volume wells might be originally constructed using additional components, such as additional pressure regulators, valves, and bypass plumbing. But as pressures and volumes decline with age, those “extra” components are removed, resulting in a wellhead similar to the typical Kentucky stripper well. And, as with any stripper well (low production and low pressure) the potential to emit from thread leaks or well site equipment is minimal. In order for the wells with higher initial production volumes to have the long production life they are capable of, the Quad Oa fugitive emission survey requirements using optical gas imaging need to come to an end once the wells reach the stripper well production levels.

Low volume, low pressure wells and producing facilities, typical of the Appalachian and Illinois Basins, do not have the potential for fugitive emissions that deep high volume high pressure wells and their production facilities do, yet are treated alike by Quad O and Quad Oa regulations. We completely understand the need to be vigilant about identifying and eliminating fugitive methane emissions, but, stripper wells, even if fracked, should continue to be exempt from current Quad Oa requirements, or at least a new category with simplified requirements should be formulated for them. Field or small central production facilities utilizing less than 250 horse power should also be exempt, or at least have requirements simplified and rod packing requirements extended to 60 months. Audio, Visual, and Olfactory (AVO) surveys that can be documented on a five year or even two year interval, followed by any repairs necessary to eliminate or at least dramatically reduce any leak found, would be effective and affordable.

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

40 CFR Part 60
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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

Executive Summary

CountryMark, INOGA, and KOGA have reviewed the information provided by EPA related to the upcoming rule making process, which is expected to include existing sources. We find that the proposal will significantly impact most of the operators in the Illinois Basin because a majority of the operators meet the definition of a Small Business. Our general recommendations are as follows:

- Maintain a low production well exemption.
- Rules for tank battery operations need to be simplified.
- Providing an extended implementation period for Small Businesses will be beneficial.
- EPA has provided some relief to the reporting and documentation requirements from OOOOa, we continue to advocate for further reductions in documentation and reporting activities.
- Alternatives to OGI and Method 21 should be available to small businesses, if not all regulated parties.

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. An initial call was held on the afternoon of June 29, 2021 to begin the discussion with Small Entity Representatives (SER) about the upcoming rule making process. During this call EPA presented several topics to industry for the collect additional data.

EPA reviewed the submitted comments and developed a list of additional questions for industry to address. On July 29, 2021 and August 3, 2021 the SERs, EPA, SBA, and OMB participated in two web meetings to discuss the list of questions that were developed by EPA. Below are supplemental comments developed on behalf of Countrymark Energy Resources, LLC, INOGA, and KOGA to address areas that EPA has solicited feedback.

We appreciate EPA's interest in the impact that the upcoming rules will have on Small Business Entities and considering our perspective throughout the process. We have enjoyed the collaborative efforts and discussion as EPA sought to better understand the Oil and Gas industry operations and how the rules will affect our small businesses. We hope to continue productive dialogue with EPA throughout the remainder of the rulemaking process.

General Comments

Most of the INOGA and KOGA members meet the definition of a Small Entity Representative. The companies primarily operate low production wells (i.e. stripper wells), which requires a low cost structure for profitable operation. Our members do not represent "Big Oil" and the capabilities of large, multinational oil companies. The internal resources available to our members are typically limited to the small staff that is employed by the companies.

On behalf of the INOGA and KOGA members, we advocate that the low production wells that are owned and operated by our members are not a significant source of methane or VOC emissions due to the low production rates of the oil and gas wells, low pressure of the reservoirs being produced, and the low-complexity well head designs that are required for our operations. The cost of compliance that EPA is proposing will materially impact the profitability of most of our members with little to no environmental benefit. In every scenario that we have evaluated, we cannot economically justify the cost of compliance with an increase in oil or gas production.

We continue to support the low production well exemption structure that was included in the 2020 Technical Revision to OOOOa. The exemption should be based on a trailing twelve month average production rate. When the prior twelve month average production declines below 15 barrels per day, the well should be exempt from all compliance requirements. If the initial production of a well is below 15 barrels per day, the well should not be considered an affected facility. If a well is drilled or modified to increase production to be greater than 15 barrels per day, we understand the desire to monitor and control emissions.

When OOOOa was originally published, regulated companies only had 60 days to develop and implement programs that met EPA's requirements. We recommend that SERs have a longer period of time to develop and implement their programs; at least 365 days. EPA is proposing to regulate existing sources, some of which have been in service for multiple decades – providing additional time for SERs will have minimal environmental impacts. EPA has granted different implementation schedules for Small Business Refiners, we see this implementation as no different.

EPA has been requesting data from industry for the last five or more years to support development of regulations. Industry has been working with DOE, who subcontracted GSI, to complete a thorough study of emissions from marginal wells across the United States. The study results are delayed due to COVID, with results being published in the fourth quarter of 2021. While we understand that EPA has been directed by the President of the United States to issue a proposed rule by the end of September 2021, we encourage EPA to create sufficient flexibility in the regulation to include findings from the DOE study. EPA has been requesting data from industry, the data will be provided before the end of 2021.

Tank Battery Emissions Requirements

EPA requires in §60.5365a (e)(4): *A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart.*
§60.5395a (a)(3) states: *Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control…*

With these two requirements, EPA has created a challenging operating scenario because combustion systems do not operate efficiently without a sufficient volume of gas for the combustion system. The most common solution for this problem is to supplement gas flow with propane. Burning propane needlessly increases carbon emissions because operators are only burning the propane to meet EPA's regulations. We recommend that combustion systems are able to be removed from storage tanks after the emissions have been below 6 tons per year for twelve consecutive months.

We further recommend that EPA eliminate the currently burdensome verification that the storage tanks remain below the 6 tons per year. Operators should be able to estimate emissions through the volume of produced oil instead of other more rigorous methods. Any other compliance activities associated with the tank facilities after the potential to emit declines to be less than 6 tons per year should also be eliminated. Performing the additional compliance activities on tanks that are legally permitted to vent delivers no emissions reduction benefits, but only requires expensive compliance activities. The SERs are primarily the companies operating this type of equipment, so they are disproportionately affected by the higher operating costs.

Written Program Requirements

EPA requires in §60.5397a (d) (1): *If you are using optical gas imaging, your plan must include procedures to ensure that all fugitive emissions components are monitored during each survey. Example procedures include, but are not limited to, a sitemap with an observation path, a written narrative of where the fugitive emissions components are located and how they will be monitored, or an inventory of fugitive emissions components*.

Developing a procedure to include all fugitive emissions components for every existing and new well will be a very expensive task for SERs. The cost to travel to each location, evaluate the site for the optimum observation path and document site specific requirements, and then complete the formal documentation and sitemap in the office is estimated to take an average of four hours per affected facility. Most operators will use contractors to develop the plans because they do not have enough employees to undertake an activity of this magnitude. An average contractor rate of $125 per hour is used for cost estimates. This includes the contractor's time, office equipment and supplies, as well as a vehicle.

CountryMark operates 1,360 oil production wells and 340 tank facilities (1,700 total affected facilities requiring site plans). The estimated first year cost for CountryMark to create site plans for all of the existing well sites and tank facilities is approximately $850,000 ($125/hr x 4 hours per site x 1,700 site plans). There will also be an estimated $4,250 per year cost to maintain site plans (1% of sites will require plans to be updated x 2 hours per site x $125/hr).

There are approximately 770,000 low production wells and 150,000 tank facilities in the continental Unites States. The estimated first year cost to develop site plans for all of the low production wells is $460 million ($125/hr x 4 hours per site x 920,000 site plans). There will also be an estimated $2 million per year cost to maintain site plans (1% of sites will require plans to be updated x 2 hours per site x $125/hr). Most of the $460 million cost will be incurred by SERs because most of the low production wells are operated by SERs.

Developing a written compliance program is a time consuming and expensive endeavor for any oil and gas company. The publication of OOOOa was more than 600 pages. This is a large amount of information for any company to read, comprehend, and then develop a compliance program. CountryMark developed our compliance program in house. We reached out to consultants to determine the cost to create a compliance program. The one time estimated cost to create a written program is $5,000 to $10,000, depending on the number of locations and geography. With OOOOa changing several times over the past five years our program has been updated to reflect EPA's updated standards. The average cost to update the program is approximately $1,000 per year. This cost did not include the cost to develop OGI site plans for each well site or tank facility, but only a written program that complies with EPAs requirements.

In the continental United States there are approximately 15,000 oil and gas companies, most of which are SERs. Using the cost of $5,000 to $10,000 to create a written compliance program, the nationwide cost of this requirement is estimated to be $75 million to $150 million. The estimated maintenance cost to update programs is $10million to $15million (15,000 companies x $1,000 per plan for updates). While some of the 15,000 oil and gas companies already have a written compliance program, the companies that do not have a written program have not been required to develop a program because none of their facilities have become affected facilities since 2015. This will be another large cost for SERs. Exempting low production wells will minimize the impact on SERs without significant environmental impacts.

Fugitive Emissions

EPA is maintaining their proposal to use Optical Gas Imaging (OGI) or Method 21. We continue to support lower cost options such as Auditory-Visual- Olfactory (AVO) and soap bubbles as a method to identify emissions for SERs. We believe that the SERs should have the option to use AVO and soap bubble testing methods in addition to OGI or Method 21 to reduce the cost of compliance.

We have recently learned that Infrared cameras that attach to smart phones are also a useful tool in detecting emission sources. The cameras cost $200-$400, and can be attached to an iPhone or Android smart phone. While the camera is not designed to detect hydrocarbon emissions, the temperature differences caused by the emissions source can be detected. Using AVO and soap bubbles as a secondary testing technique may be an alternative to expensive OGI inspections requirements.

In the Illinois Basin there are no contractors that have an OGI camera. Companies are required to purchase a camera for $90,000 and pay for an employee to attend training or use a contractor from out of state. CountryMark decided to purchase a camera to meet our compliance requirements. We have found this to be an expensive solution to identify less than 15 leaking components per year, over the past 4 years of inspections.

From our inspections, we find that leak sources are not typically "repeat offenders". Once a leak source has been repaired, it is not found to be leaking again. Several of the leaking components have been on tank lid seals, such as thief hatches. These leaks are typically able to be detected through lower cost inspection methods, not requiring OGI techniques. Cleaning or replacing the gasket material is typically the root cause solution.

We have been performing OGI inspections since 2016. We agree with the cost estimates that EPA included on Slide 10 of the *Oil and Gas SBAR Panel Presentation_Supplemental Materials final 2021.07.22* presentation. Inspecting a well site or tank facility can range from $2,500 to $6,000, depending on distance to the location, size of the location, equipment depreciation, vehicle costs, personnel costs, and any potential repair and resurvey cost requirements.

CountryMark is currently responsible for approximately 1,800 wells in Indiana, Illinois, and Kentucky (1,360 oil production wells and 440 water supply or Class II wells). CountryMark is also responsible for approximately 340 tank facilities. Performing two inspections per year on each well and two on each tank facilities will result in almost 4,300 inspections per year. With approximately 250 working days in a year, our personnel will be required to inspect approximately 17 sites per day. We have found that we are only able to inspect up to ten well sites or tank facilities in a day.

This level of inspections will require the purchase of a second OGI camera and two full time employees to perform inspections and complete documentation. We estimate that this will increase our operating cost by $300,000 per year ($150,000 per year fully loaded employee cost – salary, benefits, and vehicle). The estimated annual cost to insure, calibrate, and repair two OGI cameras is $5,000. We also estimate that we will send one employee per year to training for OGI to maintain proficiency, at a cost of $5,000 per year. We will also incur the cost of a new OGI camera for $90,000 and need to purchase two new vehicles at a cost of $100,000 ($50,000 per truck). The annual increase in cost to perform the inspections is estimated to be $310,000 and the onetime cost is estimated to be $190,000. We will use our existing software system for data management.

While all of CountryMark's operated assets are in Indiana, Illinois, and Kentucky; extensive drive time is required to reach some of the well sites. We service our well sites from field offices that are centrally located to reduce travel time for day to day operations. Our staff that complete OGI inspections are not located in these field offices, but in our office in Evansville, Indiana. Most of our well sites can be reached in one to two hours of driving from Evansville. Some of our well sites require two to four hours of driving due to the distance and lack of primary roads to reach the locations. EPA should not underestimate the time to travel to well sites or tank facilities; or from one well site to another. We believe that our operation is not unique to other SERs, where travel time between locations will be a significant time and cost for OGI inspections.

The map in Figure 1 shows CountryMark's offices, production wells, and supporting tank facilities. Red circles show distances, in 20 mile increments, from CountryMark's office in Evansville, Indiana.

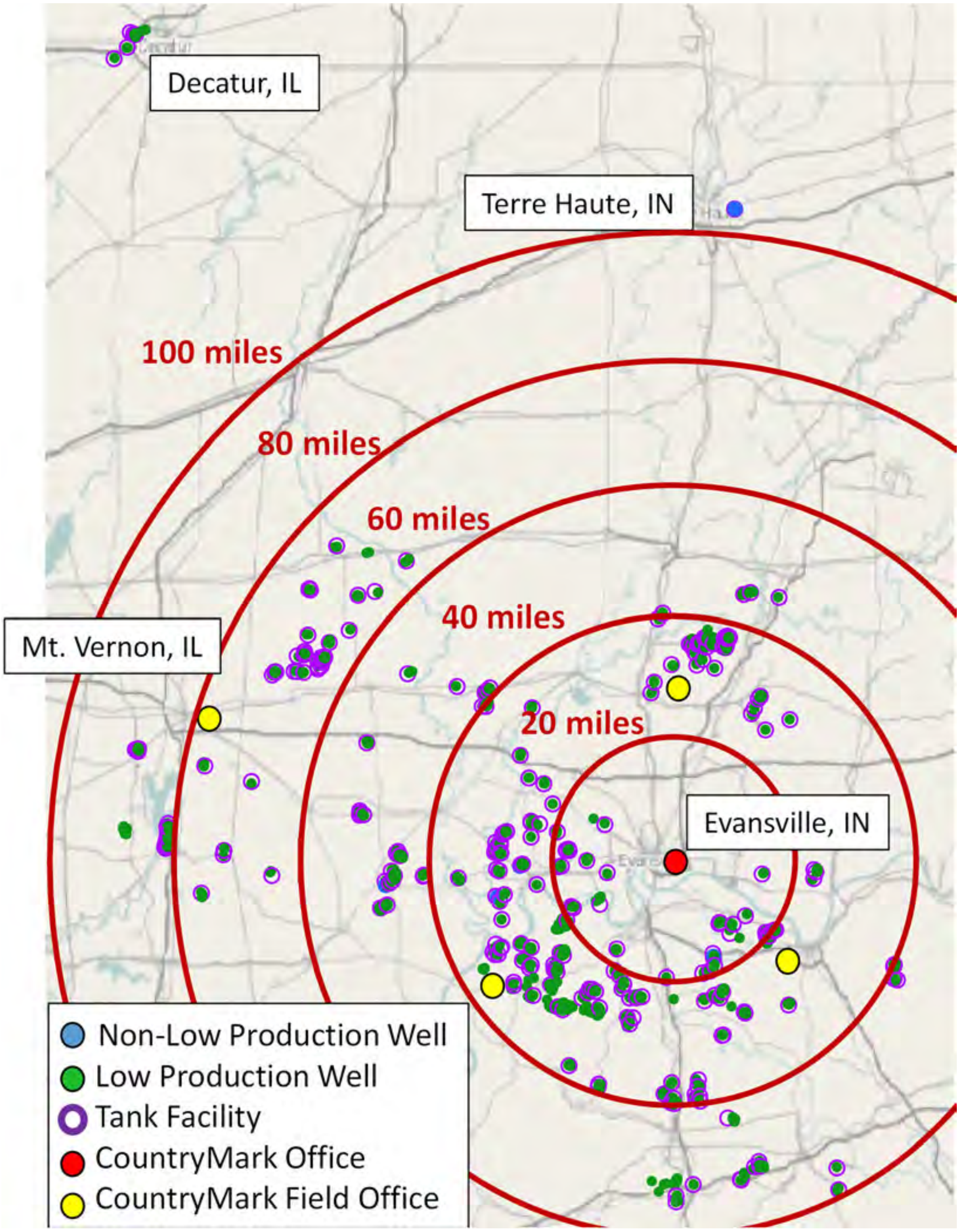

Figure 1. Map of CountryMark's Oil Production Wells and Tank Facilities

Figure 2 shows daily production from CountryMark's wells. Less than 1% of the wells produce more than 15 barrels per day. The red line in the graph is 15 barrels per day, the designation of a low production well (stripper well) is less than 15 barrels per day. All of the wells require an artificial lift system (i.e. a pump at the surface) because the reservoir pressure is too low to lift the oil to surface. In addition to the low reservoir pressure, most of the wells have a Gas to Oil Ratio (GOR) too low to sustain a flare burning at the well or at the tank facility.

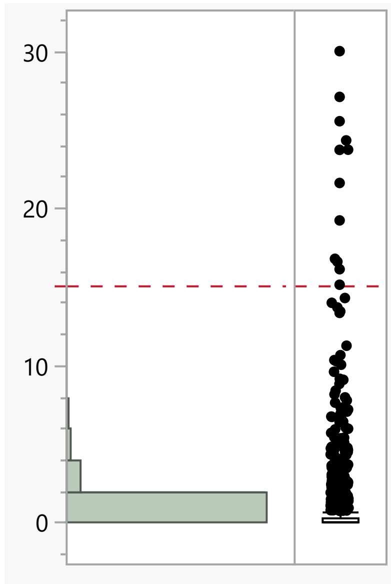

Figure 2. CountryMark's Daily Production by Well (barrels per day)

States structure their oil and gas regulations to minimize or eliminate waste from over-drilling a reservoir or from producing oil too fast that reserves are not recovered some time in the future. This is accomplished by establishing a minimum distance between well sites or production requirements. The goal is to recover as much oil as possible with the minimum number of wells in production. If an additional $5,000 per year of compliance cost is added to each well each year ($2,500 per inspection, twice per year), wells will be plugged prematurely; resulting in waste from oil reserves not being produced. This is in direct conflict with waste minimization efforts that oil and gas operators and state agencies strive to accomplish.

Figure 3 shows a typical low production decline curve for a well in the Illinois Basin. Estimated Ultimate Recovery (EUR) for the well is 14,700 barrels using the current operating and compliance costs (i.e. OOOOa compliance is not required for this well because the well was drilled prior to September 2015). Adding $5,000 per year in compliance costs reduces the operating life by 22 months and strands approximately 1,000 barrels of oil from being produced. The additional compliance cost negatively affects the project economics by increasing costs and reducing the total potential volume of oil that is recoverable. The red line on the graph shows when the economic end of life occurs with additional compliance cost included. We recommend that EPA maintain the 15 barrel per day exemption, based on the prior twelve months of production.

The loss of revenue associated with prematurely plugging a well is estimated to be $44,000 per well ($55/barrel x 1,000 barrels x 80% mineral ownership). Extending this cost to all of the wells operated by CountryMark results in a total cost of $60 million ($44,000 / well x 1,360 wells).

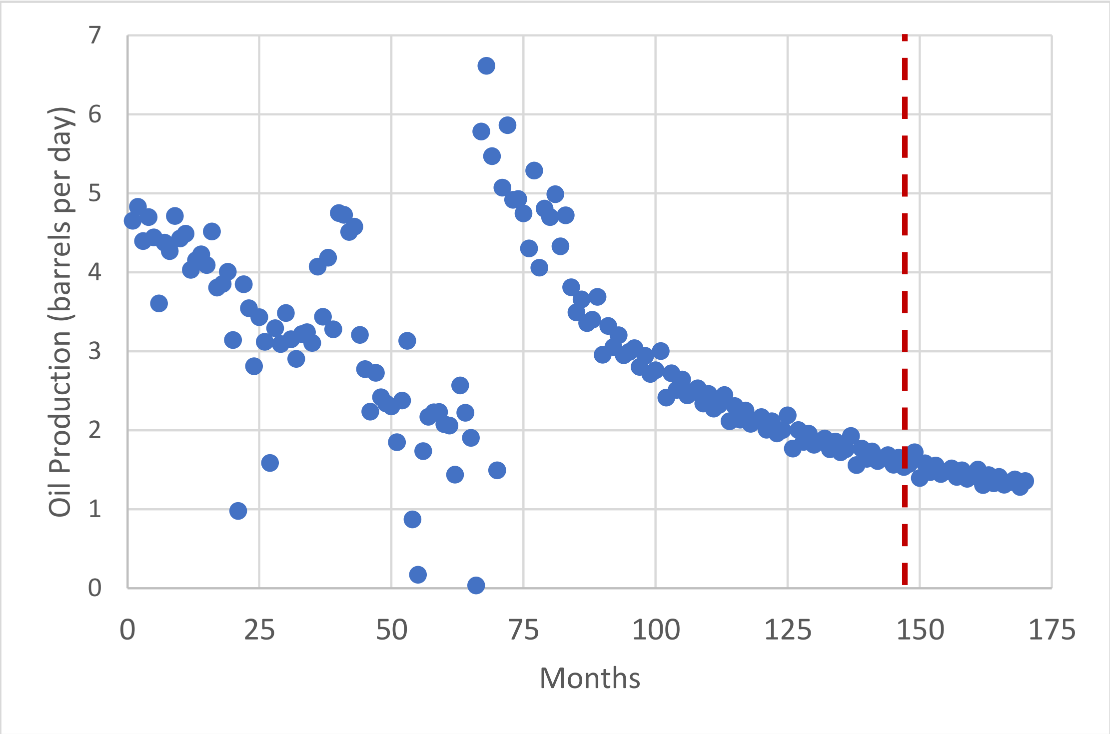

Figure 3: Decline Curve for a Sample of CountryMark's producing Fields

Our interpretation of OOOOs is that all tank that are connected to a well site that is drilled and hydraulically fracture stimulated after September 2015 are considered to be affected facilities. While the facilities have less than 6 tons per year of emissions (not requiring combustion systems), the facilities still require fugitive emissions inspections twice per year. All fugitive emission monitoring at tank facilities are applied to the oil production wells because the tanks are not revenue generating assets. The compliance cost of monitoring tank facilities also negatively impacts the production life of a well. Eliminating the fugitive emission inspections for facilities that do not require combustion systems will be a substantial cost savings by reducing inspection, documentation, recordkeeping, and reporting activities.

Low Production Well Sites

EPA has asked if there are any other characteristics of Low Production Well Sites (aside from production) that could serve as a basis of a subcategory or less stringent requirements. Production is an easy metric to use because all companies measure production using the same basis or unit of measure. The unit of measure is standardized and has financial consequences if the measurement is not completed correctly. Developing a metric that is applicable for gas and oil wells will be challenging, outside of a production metric.

Any metric that EPA is considering should be low cost to implement on new or existing wells. The cost to implement a new monitoring system on wells that were drilled 10 to 80 years ago needs to be considered in the process. Wells that were constructed prior to ~1980 do not necessarily have the same physical configuration as wells that have been drilled after ~1980.

EPA should use a trailing 12 months of average production calculation to determine if a well is considered a Low Production Well Site. EPA previously proposed using the Initial Production of the well site to categorize a well, which is not representative of the wells Potential to Emit (PTE) at any time later in the production cycle.

Other parameters that may be considered include:

- Gas to Oil Ratio (GOR) – this measurement is not routinely measured consistently at every well. Wells that do not sell gas do not invest in measurement techniques for gas that is flared.
- API gravity – this is a standard measure for crude oil and is typically measured when the crude oil is purchased. Developing a correlation between API gravity and emissions may prove challenging technically and politically.
- Well head pressure – measuring the pressure at the well head will be indicative of the well's PTE. If a local pressure gauge is the only requirement, this is a low cost method of monitoring the well performance.
- If EPA requires remote monitoring, this will be another expensive method to monitor well performance.

Recordkeeping and Reporting

EPA has requested input from SERs for ways to further reduce reporting and recordkeeping burdens. Below is a discussion about our recommendations to provide regulatory relief.

EPA currently has the reporting template set up for all affected facilities to have data reported in one sheet per equipment category (i.e. wells, centrifugal compressors, controllers…). Reporting data in this format requires operators to enter data from work that was completed in prior years. For example, a well that was drilled and hydraulically fracture stimulated in 2017 is required to provide all well completion data in the year that it was drilled and completed. For each subsequent reporting template, the same data is requested again. We recommend that EPA amend the template to report for existing sources and new sources on separate sheets in the reporting template. Only the necessary information from annual monitoring will need to be entered for wells that newly affected facilities, whereby simplifying the reporting template and reducing the volume of data for operators to input each year.

§60.5420a (b)(2)

> (v) *The date and time of each attempt to direct flowback to a separator as required in §60.5375a(a)(1)(ii).*
> (vii) *The duration (in hours) of flowback.*
> (viii) *The duration (in hours) of recovery and disposition of recovery (i.e., routed to the gas flow line or collection system, re-injected into the well or another well, used as an onsite fuel source, or used for another useful purpose that a purchased fuel or raw material would serve).*
> (ix) *The duration (in hours) of combustion.*
> (x) *The duration (in hours) of venting.*
> (xi) *The specific reasons for venting in lieu of capture or combustion.*

(xii) *For any deviations recorded as specified in paragraph (c)(1)(ii) of this section, the date and time the deviation began, the duration of the deviation, and a description of the deviation.*

We are recommending that operators are required to maintain records in the well completion logs, but are not required to report this information to EPA unless requested. In the annual report, we recommend that EPA amend the reporting template to only basic information such as to request the number of attempts to route flowback to a separator. This will reduce the volume of duplicative documentation in recording data in well completion logs and also in EPA's annual reporting template.

EPA has requested industry to provide areas that reporting and recordkeeping may be reduced due to non-value activities. EPA requested the data to be collected and reported; industry has not requested the data to be collected and reported. We respectfully request that EPA reconsider the data collection request to collect value added data, not a large volume of data just to ensure that companies are complying with the regulation. What data helps EPA to better understand our industry for better decision making? Industry has been submitting data to EPA for the past five years. Sufficient data should be available for review to determine what is value-added. The additional recordkeeping and reporting activities do not result in reduced emissions to benefit the environment.

Cost Summary

Table 1 is a summary of the cost estimate for CountryMark presented above. This cost does not cover the full implementation cost of a compliance program, but just the sections that have been discussed. The largest cost will be from the lost revenue associated with wells being plugged prematurely. Plugging all 1,360 productions before recovering the remaining 1,000 barrels of oil results in an estimated lost revenue of $61 million ($55/barrel x 1,000 barrels x 80% ownership x 1,360 wells). Annual and onetime costs have been estimated.

Cost to CountryMark	Annual	One Time	Comment
OGI Survey Site Plan	$ 4,250	$ 850,000	
Written Compliance Program	$ 1,000	$ 7,500	Note: program was created in 2016
Facility Inspection Cost	$ 300,000	$ 190,000	2 employees, 2 trucks, 1 OGI camera
OGI Camera Repair/Calibration	$ 5,000	$ -	
Employee OGI Training	$ 5,000	$ -	
Lost Revenue	$ -	$ 60,000,000	$55/barrel x 1000 barrels x 80% mineral ownership x 1,360 wells
Total	$ 315,250	$ 61,047,500	

Table 1. Estimated Compliance Cost for CountryMark

Table 2 is a summary of the cost estimate for the 770,000 low production wells presented above. This cost does not cover the full implementation cost of a compliance program, but just the sections that have been discussed. The largest cost will be from the lost revenue associated with wells being plugged prematurely. Plugging all 770,000 productions before recovering the remaining 1,000 barrels of oil results in an estimated lost revenue of $34 billion ($55/barrel x 1,000 barrels x 80% ownership x 770,000 wells). The second largest cost will be the annual well and facility inspection costs at an estimated cost of $1.8 billion. Employee training and OGI camera calibration/repair costs were not included because they are expected to be included in the estimated cost of $2,368/site. SERs are expected to incur a majority of these cost because they are primarily the operators of the low production wells. Annual and onetime costs have been estimated.

Cost to Small Entities	Annual	One Time	Comment
OGI Survey Site Plan	$ 2,000,000	$ 460,000,000	
Written Compliance Program	$ 15,000,000	$ 150,000,000	
Facility inspection costs	$ 1,823,000,000	$ -	$2,368/well x 770,000 wells
Lost Revenue	$ -	$ 33,880,000,000	$55/barrel x 1000 barrels x 80% mineral ownership x 770,000 wells
Total	$ 1,840,000,000	$ 34,490,000,000	

Table 2. Estimated Compliance Cost for Low Production Wells

Contact Information

For further information or any questions, please contact Charles E. Venditti, Manager, Regulatory Compliance at Countrymark Energy Resources, LLC; Vice-President Indiana at Oil and Gas Association; and Tech and Regulatory Committee Chairman at Kentucky Oil and Gas Association.

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Ash Titzer, Vice President of Production and Midstream
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MICHIGAN OIL AND GAS ASSOCIATION

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August 12, 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: *Final 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) and Fore Energy Partners, Inc. (FEPI) with regards to Executive Order 13990 and proposed amendments to Federal New Source Pollution Standards (NSPS), Subpart OOOOa and the correlated intricacies related to the possible expansion and application of proposed regulations to low and marginal well production.

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.

Fore Energy Partners, Inc. (FEPI) is private, small business engaged in the production of oil and natural gas in the State of Michigan.

MOGA and FEPI are participating as a small-entity representatives (SERs) 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 & FEPI 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 response has been organized into three distinct segments; 1.) Comments regarding the SBAR panel & meetings, 2.) New Source Performance Standards (NSPS) and Low Production & Marginal Well Discussion and 3.) Financial Impact Analysis & Comments.

All segments are specifically related to the statements and objectives outlined in the United States Environmental Protection Agency (USEPA), Office of Air Quality Planning and Standards document titled, "*Congressional Review Act Resolution to Disapprove EPA's 2020 Oil and Gas Policy Rule*" dated June 30, 2021 and the Biden Administration's Executive Order 13990, signed on January 20, 2021.

Executive Order 13990 stipulates "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis" and directs the USEPA to consider the following steps by September 2021:

1. Propose a rule to reduce methane emission from the oil and natural gas sector by suspending, revising, or rescinding the NSPS modifications finalized in 2020.

2. Propose new regulations to establish comprehensive standards of performance and emission guidelines for methane and VOC emissions from existing operation in the oil and natural gas sector, including the exploration and production, processing and transmission and storage segments.

MOGA and FEPI are providing SBAR panel review, discussion, rebuttal and potential cost reducing options along with evidence and 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.

SBAR Panel Comments

MOGA and FEPI appreciate the opportunity to represent the Michigan oil and natural gas producers as Small Entity Representatives during the SBA & EPA hosted online Zoom meetings that occurred on June 29th, 2021, July 29th, 2021 and August 3rd, 2021.

MOGA and FEPI hope that fruitful discussions and dialogue with the SBA and EPA will lead to a better understanding of why the small oil and gas producers and operators of Michigan and throughout the United States so vehemently oppose several components of the current 2016 NSPS Subpart OOOOa regulations based on pragmatic reasoning, operational considerations, cost/benefit analysis and limitations on marginal cost allocation. To further illustrate the potential impacts of the EPA's proposed actions, MOGA and FEPI would like to highlight the following EPA data table provided to all SBAR panel participants in June, 2021.

The table below indicates that approximately 98.8-99% of all oil companies are owned by small businesses and that approximately 92.9-93.7% of all natural gas companies are owned by small businesses.

NAICS	Description	Total firms	Small business percentage
211120	Crude Petroleum Extraction	4,461	98.8 – 99.0%
211130	Natural Gas Extraction	617	92.9 – 93.7%
213111	Drilling Oil and Gas Wells	1,725	98.1%
213112	Support Activities for Oil and Gas Operations	8,487	96.7 – 97.1%
486210	Pipeline Transportation of Natural Gas	128	31.3 – 39.8%

Potential effects of burdensome regulations on these small companies will have a large-scale ripple effect on the employment, income tax generation, private and government royalties, leasing contracts, restaurants, hotels, small communities and families. In Michigan alone, the MOGA membership constitutes around 650 members, many of which are small business and include oil and gas companies, environmental consultants, service and vendor companies, accounting and legal firms, general contractors, electricians, plumbers, welders and surveyors. In total, the oil and gas industry in Michigan directly or indirectly employs roughly 47,000 voting residents.

To initiate our response, MOGA & FEPI thought a brief, bullet-point summary of our interpretations of the SBAR panel meetings would be appropriate. Several key issues were brought to light during the meetings and we felt obliged to comment.

1. MOGA & FEPI appreciated the candor and collaborative effort of the EPA and SBA staff. We believe many of the complexities and impracticalities of the current NSPS and the possible extension to marginal and low production wells were communicated and understood by all parties.

2. MOGA & FEPI felt that the applicability of the existing regulations discussed among the SERs from various regions, struggled to apply in a pragmatic fashion to the wide variety of producing basins characteristics and operational necessities. For example, a hydraulically fractured well in West Virginia or Kentucky is significantly different from a hydraulically fractured well in North Dakota or Wyoming. Operational requirements, techniques and equipment used in Colorado for production can be substantially different from production in Pennsylvania. Operational and variable costs can be drastically different in Michigan versus Kentucky because of temperature, snowfall and general seasonal variation. Production downhole production pressures for a non-marginal well (i.e. > 15 barrel of oil equivalent (BOE)) can be dramatically different for each production region across the United States. The amount of flash gas generated by low or marginal production wells can be substantially lower than non-marginal wells and limits the ability to operate equipment required for current NSPS rules. For the above reasons, we felt that sub-categorization of marginal and low production wells from non-marginal

wells may help alleviate confusion when trying to apply regulations written for non-marginal wells.

3. MOGA & FEPI felt the EPA appeared unclear of the specific scope of intentions and focus regarding the proposed actions and regulations. When asked about the specific intentions of the Biden Administration, various EPA members were only able to reference Executive Order 13990 and could not further elaborate. This vagueness made providing adequate comment and response a daunting task given the short response time.

4. MOGA & FEPI felt that a condensed response time to facilitate an adequate response to the EPA and SBA was much too short. During previous NSPS OOOO and NSPS OOOOa rulemaking events under the Obama and Trump administrations, the duration of response time was much longer and allowed a more in-depth analysis and comprehensive response.

5. MOGA & FEPI felt that more time was necessary to address the concerns and comments of the participating SERs submitted on July 13, 2021 and following the initial SBAR panel discussion. The follow-up SBAR panel needed 2 separate meetings (July 29, 2021 & August 3, 2021) to discuss SER comments. Time constraints limited the EPA's response to SER comments and required skipping through material. MOGA & FEPI would have preferred that adequate time would have been provided to address the various comments and concerns and to individually address each source category as it pertains to proposed changes.

6. MOGA and FEPI felt a disconnect and general lack of understanding of the EPA's previous rulemaking intentions and how the SERs understood and implemented several of the source definitions and regulations. Specifically, there was a general discussion regarding the need to clarify the definition of "hydraulically fractured" well because various oil and gas producing regions interpreted the definition differentially based on specific operating parameters. The storage tank segment was particularly difficult to understand and implement. Several SERs had misunderstood the rulemaking intentions of the EPA and had been incorrectly interpreting what actions were and were not regulated.

7. During our last meeting, MOGA and FEPI did not receive a response from the EPA regarding Bureau of Land Management (BLM) practices to determine oil production in Michigan. Several small-entity oil and gas producers in the State of Michigan have asked MOGA why the Mineral Leasing Act and updates to the BLM regulations highlight waste prevention including, limiting gas flaring, leak detection, reduced venting and gas capture when Michigan's small business operators are being asked to open tank hatches daily to "strap" the oil level in each tank containing oil produced from BLM property. I realize many who will read this are not lease operators, geologists and/or engineers engaged in the daily production of oil and gas, but when a thief hatch is open, all working, standing and breathing losses (including methane & VOCs) are vented from the system. MOGA and FEPI understand the frustration of Michigan's producers and the

great financial and impractical operational burden additional regulations will place on already diminishing production, but BLM required daily venting of methane and VOCs from the entire tank system and vapor recovery piping to ascertain production within ¼ of an inch, while simultaneously imposing leak detection of possible leaks is hypocritical and completely invalidates the cost benefit analysis of methane and VOC reduction.

8. During our SBAR meetings, many small-entity oil and gas companies from all over the United States voiced their concerns regarding the expansion of NSPS Subpart OOOOa regulations to marginal and low production wells. MOGA & FEPI did not receive an answer to whether the EPA had evaluated the long-term environmental costs regarding early plugging of producing wells and the correlated ripple effect on the environment resulting from the drilling of new wells. The exploration, site preparation and drilling of new wells will likely be expedited as marginal and low production wells are forced to be plugged and abandoned early by burdensome regulations. In MOGA and FEPI's opinion, the responsible long-term management of existing oil wells would offset the tremendous costs and environmental impacts related to drilling new wells to replace the lost oil production from already drilled and constructed wells and facilities.

9. Pertaining to the topic above, MOGA and FEPI were unable to voice questions and concerns regarding proposed actions to include low and marginal wells into regulations originally designed for high volume production operations. These proposed actions would create conflicting regulations to the State of Michigan's Natural Resources and Environmental Protection Act 451 of 1994, Section 324, Part 615 law to prevent the waste of resources. The genesis of the State of Michigan's regulations were to prevent over production of well early in a well's lifespan, which can damage the producing formation and create isolated and un-recoverable pockets of oil and gas. Instead, Michigan's regulations require operators to throttle production to enhance the longevity of production and protect against un-recoverable and wasted resources.

10. Many participating SERs had concerns regarding the lack of an off-ramp in the 2016 NSPS Subpart OOOOa regarding fugitive emissions monitoring. MOGA & FEPI parallel the concerns of our cohorts regarding the costs of maintaining a LDAR program, including the costs of surveys, data capture and collection, reporting and variable costs regarding repair as non-marginal well progress into the marginal and low production category. Low production and marginal wells cannot internalize the same regulatory costs as non-marginal wells.

11. MOGA and FEPI agree with many commenting SERs who questioned the EPA panel member's references to studies conducted in western states. Comparing Colorado production to Michigan or Kentucky is akin to comparing the weather. Oil and natural gas production is directly related to the producing formation, which dictates the type, amount and size of the corresponding equipment and facility design. Many participating SERs referenced the Department of Energy (DOE) funded survey which was specifically designed to assist the Federal government in efforts to update and design regulations for

the varying production regions of the United States related to component counts, leak scale, etc… MOGA and FEPI would recommend including the results of this taxpayer funded study during the review and promulgation of new rules and regulations.

To reiterate, MOGA and FEPI applaud the SBA and EPA for their efforts to engage and solicit comments from the small-entity oil and gas companies. MOGA and FEPI felt the SBAR panel process was well organized, well implemented and well received by all participating members.

MOGA and FEPI's only regrets were the time limitations to fully address all subject topics and the general lack of scope or clarity compared to previous NSPS rulemaking efforts under the Obama and Trump administrations.

Proposed NSPS & Marginal & Low Production Well Comments

MOGA and FEPI have engaged in several public commenting events including the 2018 NSPS Subpart OOOOa comment period and the 2021 pre-panel SBAR comment event. MOGA and FEPI have included these letter responses as attachments to this letter. MOGA and FEPI's concerns with the proposed actions and regulations have remained largely unchanged over the various rulemaking endeavors. However, to allow for new comments while reducing lengthy reiteration of prior comments, MOGA and FEPI are presenting new comments along with a brief summary of the previously stated concerns referenced in the attachments to this letter response.

The below topics are summarized below:

1. Professional Engineering Certification (PEC)
    a. The requirement of a PEC is exceptionally insulting to the men and women who through experience, education or both have developed a comprehensive knowledge of designing, building, drilling, operating and maintaining oil and gas well sites and facilities. In many cases, small business producers begin with an education foundation, but develop a comprehensive in-depth understanding of the operational and engineering principles regarding the safe and efficient operation of oil and natural gas facilities through applied experience. This applied knowledge can be compared to a journeyman program where experience is interwoven with a formal education. The outcome is an exceptionally well-rounded individual who can comprehend and execute the correct engineering principles while simultaneously understanding and integrating the practical and real-world knowledge gained only from applied experience. This example can apply to almost all small business oil and gas operators in the State of Michigan. In most cases, the cost to onboard an external 3rd party engineer to review and stamp engineering designs can cost upwards of $10,000 per facility. These costs would create an excessive burden of small business operators, especially when considering the additional proposed and new regulations. MOGA and FEPI recommend expanding the PEC to include those with a mathematical, geological and other related educational disciplines combined with a fixed amount of experience in the design, operation, construction and maintenance of oil and natural gas facilities.

2. Provisions to include a "Off-Ramp" for Non-Marginal Wells
    a. Initial production for a new well is significantly higher in the first years following completion. The 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. As production significantly declines within the first couple of years of operation, 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 from a new well will 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. Once a well reaches marginal and low-production status, the continued production and well life are dependent upon cost minimization. Many of the wells discussed above would continue to produce well after the initial production decline with carefully managed costs focused on properly maintaining operating equipment. The lack of an "off-ramp" for former non-low production wells adds additional financial burdens to declining wells and may further accelerate the economic viability of these wells.

3. OOOOa and Flexible LDAR Schedules
    a. With regards to the initial monitoring period of non-low production well sites, MOGA and FEPI respectfully requests the language to be amended to allow the initial survey to be conducted within the first 60 days or during the next applicable monitoring period. The purpose of this proposed amendment would allow companies to exceed the 60-day initial monitoring period in situations when the current 60-day initial monitoring window falls before the next schedule monitoring period for developed areas with required emission monitoring requirements. This allowance would reduce monitoring costs, while efficiently distributing monitoring costs across multiple sites rather than placing the burden on a single well site. For consideration; a single day of optical gas monitoring costs approximately $2500 to $3500, and a significant portion of these costs is mobilization. The burden on a single well site is often excessive in many situations. Allowing the initial monitoring period to extend to the next scheduled monitoring event would allow a company or companies to share mobilization and other expenses across multiple regional well sites to reduce costs. In the spirit of the emission reduction efforts enacted by the EPA, this allowance would minimize secondary emissions as the result of excessive travel.

4. Expansion of NSPS OOOOa Regulations
    a. The expansion of NSPS regulations to include existing and marginal wells does not allow for 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

remaining reserve 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.

5. Conflicting Regulations
    a. 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 marginal and low production wells in addition to artificial resource recovery and ultimately lead to early plugging. The proposed regulations would lead to actions that directly contradict the State of Michigan's regulations to avoid waste.

6. Non-Marginal & Low Production Subcategorization
    a. MOGA and FEPI recommend that the EPA consider a sub-categorization of low and marginal wells to allow for specific regulations focused on a cost conducive implementation of methane and VOC reductions. MOGA and FEPI also ask the EPA consider the following discussions and options for marginal and low production wells.

    b. Use the U.S. Tax Code definition of "stripper wells" as the marginal and low production well definition threshold. The Internal Revenue Service's (IRS) Tax Code definition and the Subpart OOOOa definition use the same threshold of 15 barrels/day BOE to delineate between non-marginal and marginal and low production wells. The IRS Tax Code is well understood by both small-entity producers and federal and state agencies. By utilizing this definition, small-entity producers could annually evaluate and document their production rate and apply to regulations that specifically apply to each well and facility. The use of the IRS Tax Code definition would also allow the EPA to adequately address enforcement and compliance concerns during audits by asking small business producers to supply their annual production determination. The current method of an initial, one-time evaluation of the first 30-days of production does not adequately address production decline that effect all wells.

c. Utilize the DoE study currently in process to develop emission data for various producing regions in the United States. The DoE study titled "*Quantification of Methane Emissions for Marginal (Small Producing) Oil and Gas Wells"* was designed to determine the component counts and associated emissions for marginal and low production wells. Application of non-marginal well regulations including techniques, implemental costs and cost benefit analysis does not translate to marginal and low production wells and this study would help tailor regulations.

d. The current EPA updated "model plant" is based on 22 wells in one production basin. MOGA and FEPI believe the EPA is over-estimating the average number of wells that can share implementation and on-going annual regulation costs. Producing basins are not static and often add and subtract production assets based on formation evaluation. While wells and assets per basin and region can be greater than 22 wells, there are far more instances where the number of wells and assets will be far less than 22. The model well assumption of 22 wells and the associated costs will definitely benefit basins and regions with more than 22 wells, but will disproportionately punish basins and regions where less than 22 wells can share the estimated costs. In many cases, only a handful of remaining wells are left in producing regions as depletion and plugging actions are employed in response to production decline.

e. There is tremendous variation between producing basins and operational requirements that apply to the approximately 770,000 marginal and low production wells in the United States. The EPA's current model plant generalizes production basins, operational requirements, state laws and regulations and does not allow for the accurate representation of the production and operational regimes across United States. For these reasons, MOGA and FEPI recommend the EPA use the above-mentioned DoE study to develop adequate regulations and standards based on regional basins and the subcategorization of marginal and low production wells and facilities by region.

f. MOGA and FEPI would suggest the following approaches to minimizing the cost burden on small businesses who operate marginal and low production wells across the United States:

    1. Require semi-annual Auditory, Visual & Olfactory (AVO) surveys instead of traditional LDAR (OGI, sniffer, laser) for low production and marginal wells and associated facilities. This would allow small businesses to internalize costs, minimize third-party consultant expenses, remove cost prohibitive technology purchases, while accomplishing the desired proactive prevention of methane and VOC emissions. AVO is currently considered acceptable for evaluating closed-loop systems on tank batteries.

2. MOGA and FEPI question how the EPA would review annual reporting for the roughly 770,000 marginal and low production wells in the United States. MOGA and FEPI suggest the removal of annual reporting and require small businesses to retain records for 5 years. Should the EPA or a state agency request the records and documentation, the small businesses would have specific time frame to produce the required data. This would put the responsibility on each small business to complete the regulation objectives, but remove the exorbitant cost of annual reporting that may never be actually reviewed.

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 of wells with a remaining viable production horizon. To illustrate this effect, the following cost breakdown highlights the minimized economic returns from marginal and low production wells and emphasizes the potential effects of implementing proposed NSPS regulations:

Estimated Gross Revenue Projection for a Typical Marginal/Low Production Well in Michigan	
Factors & Constants	
Remaining Reserves (Bbls)	1,200
Annual Decline Rate (%)	5.0%
Production Life (Years)	15
Initial Production Rate (Bbls/day)	10
Final Production Rate (Bbls/day)	2
Commodity Price per Barrel (Average)	$60.00
Royalites (%)	12.5%
Severance Tax ($/Bbl)	$3.00
Deduction for Quality of Crude ($/Bbls)	$3.00
Transportation Charges ($/Bbl)	$4.00
Fixed Operational Costs ($/Bbl)	$4.00
*Variable Operational Costs ($/Bbl)	$4.00
Months in Year	12
2016 EPA Estimated One-Time Initial Costs per well	$1,366.00
2016 EPA Estimated On-going Annual Costs per well	$2,804.00
*Estimated One-time Cost for Professional Engineering Certification	$3,500

Potential Gross Revenue over Remaining Well Life	$ 72,000.00
Royalities	($9,000)
Severance Taxes	($9,000)
Deduction for Quality of Crude	($3,600)

Transportation Charges	($4,800)
Fixed Operational Costs	($4,800)
*Variable Operational Costs	($4,800)

Potential Gross Revenue before Regulations	$ 36,000.00
2016 EPA Estimated On-going Annual Costs per well	($1,366)
2016 EPA Estimated Ongoing Annual Costs over remaining life	($33,648)
*Estimated One-time Cost for Professional Engineering Certification	($3,500)

Potential Gross Revenue after Regulations	($2,514)

The above estimated costs for initial and on-going annual costs were taken from the updated 2016 estimated costs for implementation of the 2016 NSPS regulations.

The above estimated one-time cost for Professional Engineering Certification required for each individual well site and facility is based on actual cost estimates from regional consulting firms.

The above Variable Operational Costs are specific to Michigan and include seasonal variation in requirements pertaining to snowfall, temperatures, travel restrictions, formation dynamics, operational agendas, resource recovery costs, land-owner contracts, royalties, etc.

The illustration of economic loss from typical marginal and low production well in Michigan shown above would lead to the violation of the State of Michigan's Part 615 rules and regulations regarding early plugging of viable producing wells discussed. MOGA & FEPI view these outlined costs related to proposed EPA actions as having a significant impact on small-entity oil and natural gas producers and consider the potential outcomes 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 vast majority of Michigan's oil and natural gas wells are family-owned businesses who live, work and play in the immediate vicinity of their production assets.

For these reasons, MOGA and FEPI 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 and FEPI 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 and FEPI estimate 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 and FEPI'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 and FEPI 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 and FEPI 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 and FEPI 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.

Conclusion

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 and FEPI implores the SBA to continue to advocate for the exemption of 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
Environmental Chairman - Michigan Oil & Gas Association (MOGA)

J. Scott Huber
Partner – Fore Energy Partners, Inc. (FEPI) and
Ad Hoc Quality Chairman – Michigan Oil and Gas Association (MOGA)

Enclosures: *2018 MOGA Letter to Open Comment Period for NSPS Modifications*
2021 MOGA Letter to EPA & SBA Pre-Panel SBAR Group
2021 FEPI Letter to EPA & SBA Pre-Panel SBAR Group

MICHIGAN OIL AND GAS ASSOCIATION

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

December 17, 2018

The Honorable Andrew Wheeler, Acting Administrator
U.S. Environmental Protection Agency
1200 Pennsylvania Avenue, N.W.
Washington, D.C. 20460

Re: U.S. Environmental Protection Agency's Oil and Natural Gas Sector: Emissions Standards for New, Reconstructed, and Modified Sources Reconsideration at 83 Federal Register 52056 (October 15, 2018)

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

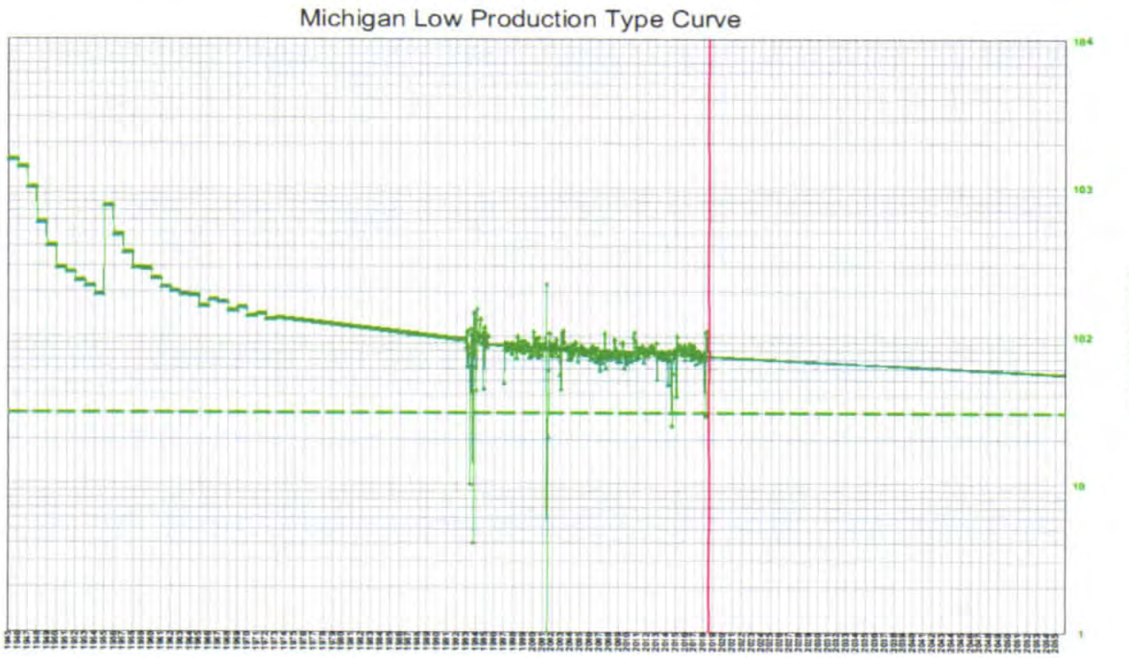
Dear Acting Administrator Wheeler,

Upon publication in the Federal Register on October 13, 2018, the Environmental Protection Agency's (EPA) opened a public comment and support data period to gather input related to improving Subpart OOOO(a) of the Clean Air Act. In response to this call for comments, Michigan Oil and Gas Association (MOGA) would like to offer its recommendations for the amendment of OOOO(a). MOGA is submitting the following comments, recommendations and supporting evidence for the proposed augmentation of the Professional Engineering Certification, frequency of monitoring, exemption for low production wells, flexibility for the initial monitoring period and inclusion of an "off-ramp" for non-low production well sites that become low-production sites. MOGA's comments and recommendation are supported by data collected from the Michigan Basin regarding production decline curves, potential emissions analysis, economic viability, operating cost consideration and State of Michigan laws and regulations to prevent waste from early plugging and abandonment.

MOGA would like to initially commend the EPA for their willingness to address the concerns and comments of stakeholders subject to Subpart OOOOa regulations.

1.0 Data Collection:

Michigan Oil and Gas Association (MOGA) immediately recognized that Subpart OOOO(a) discriminated against the fair operation of low-producing wells in Michigan. Oil and gas wells have finite lifespans with rapid production declines occurring immediately after the initial completion. Please note the production curve of Michigan wells below. MOGA created this curve by compiling the production histories of three major oil-producing formations recorded since the 1940s (Michigan Department of Environmental Quality database). The curve illustrates how the most onerous burden of the Clean Air Act (OOOOa) comes when these wells are at the marginal production period of their lifespans.

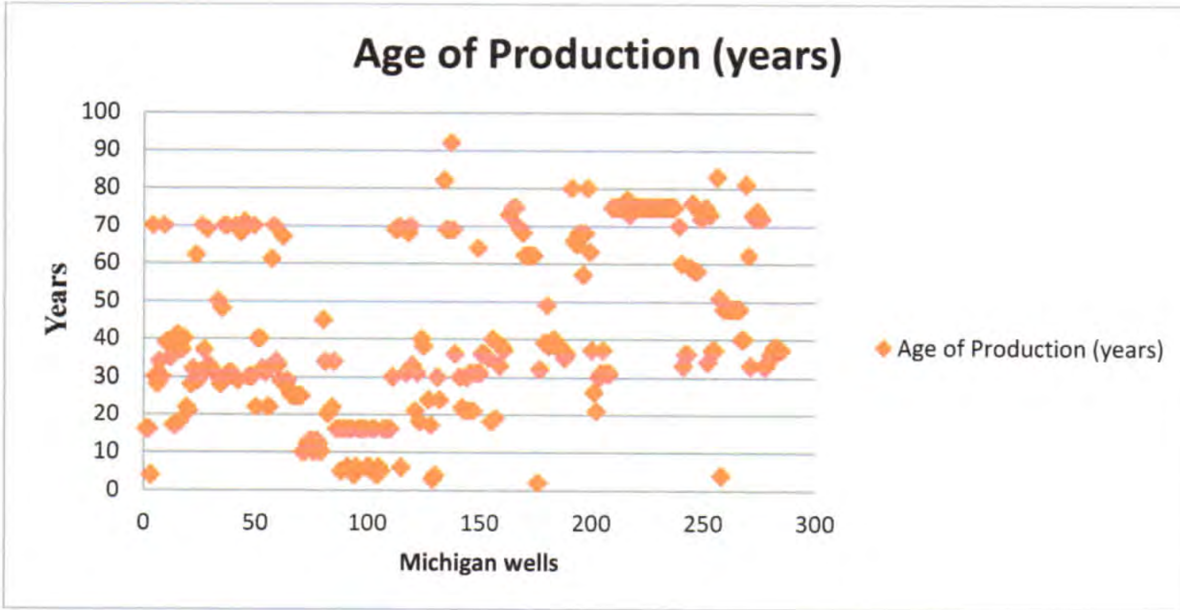


Along with this historical analysis, MOGA membership built a database that cataloged the fugitive component counts at low production well sites across the state. Attachment 1 is the Low Production Well Site Component Survey sheet which MOGA distributed to the operators participating in the survey. The format of the survey was taken from Environmental Defense Fund's (EDF) Fort Worth study, and it was aimed specially at wells making less than 15 BOEPD, e.g. stripper wells or low-producing wells. The EDF study was general and lacked specific data focusing on low producing wells, but emphasized non-low producing operations.

Finally, MOGA evaluated the state's oil well count and the associated production on a county-by-county basis. Michigan has 84 counties of which 49 have active production. There are an estimated 3,746 oil wells producing at an average rate of 3.2 BPD. These numbers clearly display how many of Michigan's wells fall into the marginal category.

The production curve presented on this page portrays the typical production life of the majority of oil producing wells in the state. The observed curve demonstrates that the initial production period generates the largest amount of recoverable reserves and generally occurs in the first 30%

of the well's lifespan. As a well ages, its capital and operating expenses increase while its production rates and profit margins fall. From the data MOGA gathered, the age of Michigan's oil wells varies, and the following graph readily displays this variety. The horizontal axis uses numbers to identify specific wells and vertical axis denotes each well's years of operation. This graph and the one above support the study's conclusions, and the sample size is adequate to take into account the operation, economics, and life expectancy of stripper wells in our state.



In compiling the database, MOGA noticed that most of the study participants were in the top 25 annual crude producers for Michigan by volume. It would follow that their well count was either greater than the remaining producers or that said participants have the better producing wells. Either way, the statistical variance between the numbers of marginal wells for the sample group should not be any different from the group of Michigan operators as a whole The lower annual crude producers, who did not participate, would statistically have a greater number of low producing wells because their production is only 2.72% of the top 25 producers' totals.

2.0 OOOOa and Low Producing Wells

MOGA thanks the EPA for considering an amendment of the frequency of monitoring for low production wells. As discussed in various sections of this response, Production vs. Cost is negatively correlated; i.e., as production decreases, the cost to recover remaining reserves increases. MOGA supports the arguments of our members regarding the burden of additional monitoring requirements accelerating the financial decline of operating low-production well sites resulting in the early plugging and abandonment of wells. In the State of Michigan, early plugging of wells is considered "waste" and regulated under the State of Michigan's Natural Resources and Environmental Protection Act 451 of 1994, Section 324, Part 61504 law to prevent the waste of resources. For these reasons, MOGA recommends exempting low producing wells from fugitive emissions monitoring to minimize operating costs and remove additional financial burden to extend the longevity of producing assets.

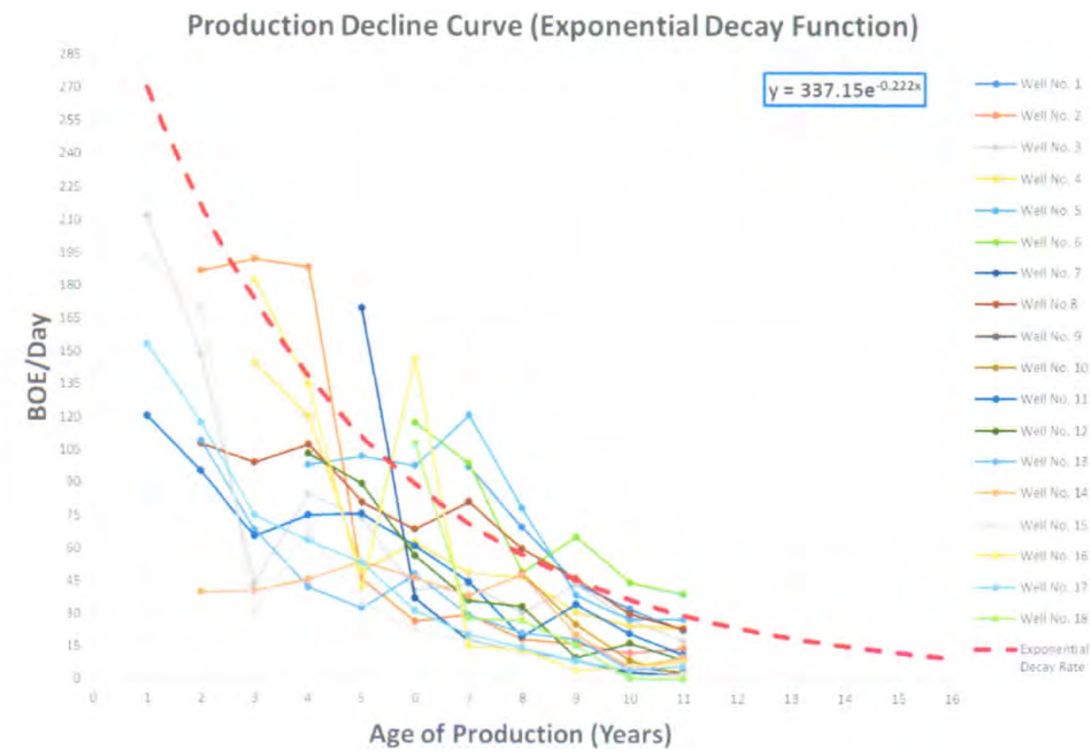
In addition to the financial burden, low producing wells in Michigan also have reduced emissions. Please refer to Section 4.0 OOOOa and Declining Production to see data on how are emissions are reduced at Michigan's low producing wells.

3.0 OOOOa and Flexible LDAR Schedules

MOGA commends the EPA for consideration of amending the monitoring requirements for the collection of fugitive emission components at all well sites. With regards to the initial monitoring period of non-low production well sites, MOGA respectfully requests the language to be amended to allow the initial survey to be conducted within the first 60 days or during the next applicable monitoring period. The purpose of this proposed amendment would allow companies to exceed the 60-day initial monitoring period in situations when the current 60-day initial monitoring window falls before the next schedule monitoring period for developed areas with required emission monitoring requirements. This allowance would reduce monitoring costs, while efficiently distributing monitoring costs across multiple sites rather than placing the burden on a single well site. For consideration; a single day of optical gas monitoring costs approximately $2500 to $3500, and a significant portion of these costs is mobilization. The burden on a single well site is often excessive in many situations. Allowing the initial monitoring period to extend to the next scheduled monitoring event would allow a company or companies to share mobilization and other expenses across multiple regional well sites to reduce costs. In the spirit of the emission reduction efforts enacted by the EPA, this allowance would minimize secondary emissions as the result of excessive travel.

4.0 OOOOa and Declining Production

MOGA further requests that EPA consider providing an "off-ramp" for non-low production wells that become low production wells during their production life. Current methodology for defining a non-low production well vs. a low-production well is based on the first 30-days of production. In many situations, the production decline curve for non-low production wells is accelerated with many non-low production wells achieving low-production status within a short time interval proportional to the longevity of viable oil and gas recovery. To offer supporting evidence, MOGA collected data on a sample of producing wells drilled within the last 11 years with current oil production below 15 barrels of oil per day. The graph below illustrates the sample of 18 Michigan oil wells and displays BOEPD production beginning in 2007 and terminating on December 31, 2017. The graph displays individual well BOEPD and the correlated production decline curve based on the relative-rate-intercept function or exponential decay rate.



The exponential decay function is a fitted rate of decline to illustrate the production decline of BOEPD over the age of production. The exponential decay function would indicate an annual BOEPD decline of 19.9 percent. The following table displays the predicted BOE as age of production increases based on an annual decline rate of 19.9 percent.

Years	y-intercept (BOE)	Exponential Decay Rate (Annual % Decline in BOE)
0	337.15	
1	270.0286	19.90846357
2	216.2701	19.90846357
3	173.214	19.90846357
4	138.7298	19.90846357
5	111.1108	19.90846357
6	88.99035	19.90846357
7	71.27374	19.90846357
8	57.08423	19.90846357
9	45.71964	19.90846357
10	36.61756	19.90846357
11	29.32757	19.90846357
12	23.4889	19.90846357
13	18.81262	19.90846357
14	15.06732	19.90846357
15	12.06765	19.90846357
16	9.665163	19.90846357

As illustrated in the above graph and table, the initial production decline is very rapid. However, as production advances in age, the decline diminishes and begins to plateau. In many cases, production stabilizes as the geologic producing horizon reaches equilibrium. The extrapolation of the exponential decay rate beyond Year 11 indicates that BOEPD achieves low-production status at Year 15 with future production directly tied to cost minimization. The negative correlation between production and costs creates an economic viability issue. Once a well reaches low-production status, continued production and well life are dependent upon cost minimization. Many of the wells depicted above would continue to produce after 15 years with carefully managed costs focused on properly maintaining operating equipment. However, the lack of an "off-ramp" for former non-low production wells adds additional financial burdens to declining wells and may further accelerate the economic viability of these wells.

To provide additional support of MOGA's request for an "off ramp" for non-low production well sites that transition to a low-production well site, MOGA is providing the following analysis of working, standing and breathing emissions from storage tanks associated with production from the 18 Michigan wells drilled within the last 11 years and represented in the exponential decay graph and table above. The following table displays the Well No., Age of Well in years 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. E&P Tanks, Version 3 was utilized to calculate potential working, standing and breathing emissions based on low pressure oil samples collected according to the California Air Resources Board (CARB) methodology.

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**

The above data indicates the average potential storage tank emission declines 93.5 percent over an average of 8.3 years. A 93.5 percent reduction achieves a similar reduction to the 95.0 percent control requirements for tank batteries with greater than 6 tpy of VOC emissions. This analysis provides additional supporting data to validate amendment to Subpart OOOOa regulations to facilitate an "off-ramp" for transitioning non-low production well sites.

5.0 Professional Engineering Certification

MOGA commends the EPA for consideration of amending the Professional Engineering Certification requirement for closed vent systems (CVS). However, many small production companies do not employ in-house engineers and rely on the education, experience and specific production horizon knowledge to properly design CVS at site facilities. In many cases, company Geoscientists have decades of experience properly designing oil and gas facilities. For this reason, MOGA requests the EPA extend the CVS certification qualification to Degreed Geoscientists with a discipline in Engineering, Geology and Statistics with experience in the design of petroleum related facilities and specific knowledge of reservoir characteristics, drive mechanisms and chemical compositions. In most cases, individual company Geoscientists, Statisticians, Engineers and Geologists have a better understanding of production variation and facility design requirements for local and regional production horizon attribute variation than an external third-party engineer. MOGA also challenges the cost estimate of $547 for external third-party engineering certifications. The cost to on-board an external third-party engineer for specific local and regional variations to producing horizon attributes would cost thousands of dollars and place an unnecessary financial and duplicative general duty obligation and compliance burden on small producers.

6.0 Conclusion:

MOGA would like to reiterate their commendation for the EPA's willingness to address the concerns and comments of stakeholders subject to Subpart OOOOa regulations. In summary, MOGA proposes pragmatic recommendations in four specific caveats of the OOOOa regulation amendments to ensure the longevity of declining production assets by removing burdensome cost overhead leading to early plugging.

First, low producing wells (15 BOEPD or less) should be exempt from the rule on economic grounds and because emission are reduced at Michigan low producing wells (Sec 2.0 and 4.0)

Second, MOGA endorses more flexible LDAR schedules for wells subject to OOOOa (Sec. 3.0).

Third, MOGA's data supports a regulatory "off-ramp" for wells, as production and associated emissions decline over time (Sec. 4.0).

Fourth, MOGA would like the CVS certification qualification to include degreed geoscientists, engineering technicians and statisticians (Sec. 5.0).

Thank you for your time and consideration.

Sincerely,

Mr. Joel Myler
Chairman, Michigan Oil and Gas Association

Ms. Erin McDonough
President, Michigan Oil and Gas Association

ATTACHMENT 1

Low Production Well Site Component Survey					
Facility Location (County)		Barrels/day:		=	
Age of Well (yrs)		Gas MCF/day:	÷ 6	=	
Operating Pressure (psia)					
Gas Sales (Y/N)			Total BOE		
Facility Type (circle one):	Single Well | Multi-Well		**Low Production Well Site = < 15 BOE*		

Type of Equipment @ *Low Production Well Site*	Count of Equipment	Valves	Connectors	Open Ended Lines (OELs)	Pressure Relief Valves (PRVs)
Oil Wellheads					
Separators (2 phase)					
Headers					
Heater Treaters (3 phase)					
Glycol Dehydrator					
Storage Vessels					
Total Count:					

Instructions, Clarifications & Assumptions:

1. Only provide information on **Low Production Oil Well Sites**.

   Low Production Oil Well Site = Less than 15 Barrels of Oil Equivalent (BOE) per day.

   Barrel of Oil Equivalent (BOE) includes both Oil & Natural Gas Produced:

   BOE (Oil) = 1 bbl Oil = 1 BOE

   BOE (Natural Gas) = 6,000 scf NG = 1 BOE

   Example: ***10 bbl/day Oil production + (12 mcf/day ÷ 6 mcf) = 10 + 2 = 12 BOE/day***

2. Count of Connectors should include Flanges for each equipment type.
3. Count of equipment should include devices and equipment capable of being operated by both compressed air and/or natural gas.
4. A "separator" is a two-phase liquid/gas vessel.
5. A "heater treater" is a three-phase oil/gas/water vessel.
6. Count of Storage Vessels includes both Oil and Water tanks located at a well site.

August 12, 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, Docket ID No. EPA-HQ-OAR-2021-0295

Dear Ms. Wiggins:

The Petroleum Alliance of Oklahoma ("Alliance") appreciates the opportunity to submit comments on EPA's Supplemental presentation provided to the SERs on July 29 and August 3 in advance of EPA's forthcoming NSPS OOOOa 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. In addition to the comments we submitted to you on July 13, we have the following comments on the Supplemental presentation.

Rule Coverage/Scope

On Slide 3, EPA request feedback on differentiating the hydraulic fracture of conventional wells (typically associated with vertical wells) versus horizontal wells. In general, the completion of a vertical well is much less involved, almost always lasting less than a day compared to many days/weeks for a horizontal well. The clean-up/drill out is also much less involved for a vertical well. This would apply both to original completions and re-completions. In general, this process generates less emissions as compared to a horizontal well completion.

Reciprocating Compressors

On Slide 17, EPA states it is re-evaluating the exemption for compressors located at well sites. This is a small emission source. In reviewing EPA's 2019 Subpart W data for the production segment, these emissions make up 0.2% of total methane emissions. Most vendors replace the rod packing every 36 months as part of their maintenance programs so this would result in minimal, if any emission reductions. The requirement to report and track records of replacement and/or changing the standard from tracking hours to flow measurement at these sites may be unnecessarily burdensome and costly on small oil and gas operators, providing no environmental benefit.

EPA is also considering changes to the rod packing changeout using emissions monitoring instead of a set period of time or hours of operation. This may be beneficial in certain operations and where larger oil and gas operators may have the resources and equipment to monitor those emissions; however, it should be an option/alternative, and not a mandatory requirement as it may unnecessarily create additional burdens and costs for smaller operators who do not have access to the same resources.

Storage Vessels

On Slide 12, EPA is considering whether methane-based applicability is appropriate. This may negatively impact many smaller oil and gas operators that have marginal/low producing 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 [IOGCC's 2016 report on marginal wells]) storing crude oil in uncontrolled tanks due to low VOC emissions. Because of a methane-based approach, small oil and gas operators would be required to conduct costly retrofits to install flares or control devices on tanks due to methane emissions. In some cases, there may not be sufficient volumes of tank vapors to feasibly route to a control device.

On Slide 12, EPA is considering applicability to tank batteries in lieu of single storage vessels. It is unclear what threshold EPA is considering for tank batteries, so the Alliance does not have enough information to make an informed comment on this issue; however, EPA should consider that smaller operators may utilize tank batteries as a cost-effective means (as well as limiting its environmental footprint) to store crude oil from several low producing wells in one central facility.

Fugitive Emissions

EPA's original leak detection and repair (LDAR) program focus was on higher production wells, and it was later expanded to lower production wells; however, its cost effectiveness for lower production wells has remained controversial. The 2020 NSPS OOOOa reconsideration regulations addressed this inconsistency by providing an off ramp from the LDAR program when new and modified well sites subject to NSPS OOOOa deplete to 15 BOE/day and less. Its action tracked the EPA Control Techniques Guidelines for existing sources in ozone nonattainment areas. This off ramp is a rational approach that needs to be supported and incorporated into any new NSPS OOOOa rule.

Centrifugal Compressors

On Slide 16, EPA states it is considering expanding applicability to dry seal compressors. What is the basis for this potential control strategy? On slide 18, EPA states it has received previous comments that indicate higher emissions from dry seals as compared to EPA's and State's estimates. If EPA has actual studies that show higher emissions, we request a copy of that information for review and feedback.

Pneumatic Controllers

On Slide 19, EPA is considering operational requirements for intermittent-bleed and low-bleed controllers (e.g., leak detection, monitoring, proper operation). It is unclear how this would work as these specific controllers are designed to vent small volumes during normal operations. In addition, EPA states it is considering expanding zero emissions controller requirements. This may work in certain scenarios where other options/alternatives exist, but it would not be feasible at sites where electricity is unavailable or insufficient. At these sites, the installation and use of gas fired compressors to supply air for these devices may defeat the purpose by ultimately increasing emissions, and the installation of electric service to the facility would be extremely expensive, especially for small operators.

In 2014, the Oklahoma Independent Petroleum Association (OIPA) conducted a survey of emissions from pneumatic controllers from production sites in Oklahoma (see attachment). In general, the results of the survey showed that existing emission factors overestimate pneumatic emissions (ranging from 5.4 to 27.5) as compared to OIPA's survey, and intermittent vent controllers generated minimal emissions relative to all emission sources at a production facility. As such, EPA should focus its efforts on emission sources where the most environmental benefits can be obtained and carefully consider if new or additional requirements for intermittent and low-bleed controllers are needed.

Low Production Wells

Finally, we would like to reiterate one of our comments submitted on July 13 regarding low production wells. When EPA developed its NSPS regulations for oil and gas, it had no emissions profile for low production wells. No extensive profile yet exists. DOE initiated a study of low production well air emissions that should be available in late 2021. President Biden's Executive Order 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.

In addition, DOE's study will be especially important as it relates to EPA's development of workable existing source emission guidelines under Section 111(d) for the oil and gas sector. This effort will help EPA make informed decisions as to different emission guidelines or compliance times or both for different sizes, types, and classes of facilities when costs of control, physical limitations, geographical location, or similar factors make subcategorization appropriate.

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

Attachment – OIPA Study

cc:
David Rostker, Small Business Administration Office of Advocacy
David.rostker@sba.gov

Pennsylvania Grade Crude Oil Coalition
P.O. Box 149
Mt. Jewett, PA 16740
Phone: (814) 230-3033
Email: admin@pagcoc.org
www.pagcoc.org

Cameron Energy Company
507 Cherry Grove Road
Clarendon, PA 16313
Phone: (814) 968-3337
Email: camelot1@atlanticbb.net

August 12, 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,

Thank you for inviting these comments from the Pennsylvania Grade Crude Oil Coalition (PGCC) and Cameron Energy Company. These comments (the "August 12, 2021 comments") are intended to supplement the written comments I provided on July 13, 2021. These August 12, 2021 Comments are prepared in the response to the Supplemental Materials provided by the EPA team, and these August 12, 2021 comments are intended to supplement the questions and comments I raised during the teleconferences you and your EPA team conducted on July 29, 2021 and August 3, 2021.

As I previously noted in my July 13, 2021 written comments, 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.

In the comments I submitted July 13, 2021 I noted that the short (two-week) timeframe permitted by EPA for the submission of materials and comments impeded my ability to respond in a thorough manner. I have been able to rectify that problem in part. Following the submission of comments on July 13, 2021 I met with the members of the PGCC Legal and Legislative Committees on July 15, 2021. As a result of that meeting, I am able to provide more detailed information about Pennsylvania's conventional wells. Further, during that committee meeting several PGCC committee members reminded that their companies operate conventional oil and gas wells in both Pennsylvania and New York State. Indeed, the same Upper Devonian sandstones that are the target formations for PGCC member operations are the target formations just across the border in New York State. The New York State wells are equipped, and function, in the same manner as those in Pennsylvania. At the direction of the PGCC committees, I made outreach to the Independent Oil and Gas Association of NY (IOGANY) and learned that IOGANY was already undertaking studies of methane emissions from New York State conventional wells. Given that the EPA timeline for response does not permit PGCC to undertake emission sampling, and given that IOGANY already has that sampling in hand, I will provide to you the IOGANY sampling results. Given the similarity of the conventional wells as between Pennsylvania and New York State, the IOGANY data will be a useful resource.

1. Qualities of Conventional Wells:

Many of the topics addressed in our Panel discussions relate to well qualities or infrastructure that are not representative of conventional wells located in Pennsylvania and New York State. Instead, several of the topics and questions are unique to shale (unconventional) well development. That shale development represents the focus of most new drilling, and therefore most new oil and gas sources, in the United States. Typical of this new development are the unconventional Marcellus and Utica shale wells in Pennsylvania.

The Pennsylvania and New York State conventional oil and gas industry differs significantly from the unconventional industry, from the size of the site needed to drill a well to the resources needed to complete and bring it on line. According to DEP's *Act 13 Frequently Asked Questions*:

> A conventional gas well, also known as a traditional well, is a well that produces oil or gas from a conventional formation. Conventional formations are variable in age, occurring both above and below the Elk Sandstone. While a limited number of such gas wells are capable of producing sufficient quantities of gas without stimulation by hydraulic fracturing, most conventional wells require this stimulation technique due to the reservoir characteristics in Pennsylvania. Stimulation of conventional wells, however, generally does not require the volume of fluids typically required for unconventional wells.
> http://files.dep.state.pa.us/OilGas/OilGasLandingPageFiles/Act13/Act_13_FAQ.pdf

DEP's description focuses on one operational distinction between conventional and unconventional wells – the volume of fluids required for hydraulic fracturing. While this is an important factor distinguishing the two types of operations, there are other differences between conventional and unconventional activities and operations that impact our panel discussion:

- A typical well pad cleared for a conventional oil or natural gas well is more than 35 times smaller than that of a typical unconventional well. There are two primary reasons for this difference. First, the high-volume hydrofracturing process associated with the unconventional well requires fleets of high-pressure pumps, multiple tanks to contain stimulation, flowback and other fluids, multiple containers and vehicles to mobilize proppants, numerous sanitation facilities for the many workers, and the like. In contrast, Pennsylvania and New York state conventional wells sometimes do not involve hydrofracture at all. When hydrofracture is utilized, it is always a small-flow process, utilizing less than 10% of the pumping capacity of a Marcellus or Utica shale well, and requiring few tanks for stimulation supply, and few (and sometimes zero) tanks for flowback, inasmuch as flowback is frequently not associated with Pennsylvania and New York State conventional wells. Second, following completion of an unconventional well the well site must be of adequate size to accommodate the many items of required production infrastructure. In contrast, the Pennsylvania and New York State conventional wells require far fewer infrastructure items.

- Wellhead pressures of new conventional wells are only several hundred pounds and quickly reduce to very low pressures. The vast majority of conventional wells in Pennsylvania and New York State operate at less than 50 psi and most at less than 20 psi. Wellhead pressures of new unconventional wells are measured in thousands of pounds and unconventional wells employ safety measures and equipment entirely unnecessary in the conventional well industry.

The substantially greater pressures, and the items of infrastructure, associated with unconventional wells establish the potential for significant fugitive leak emissions. The pressures involved in conventional wells are orders of magnitude lower than unconventional wells and those lower pressures result in the need for far fewer (or no) items of associated infrastructure. Accordingly, it is the experience of the conventional oil and gas industry in Pennsylvania and New York State that fugitive emissions are non-existent in the majority of well sites and very limited in scope where such emissions exist.

Another key distinction is the substantially lower production yielded from conventional wells and the smaller return on investment compared to unconventional shale wells. Conventional wells have lower profitability than unconventional wells and are strongly influenced by oil and natural gas commodity prices and other market forces. For details as to costs and profitability I refer you to my comments submitted July 13, 2021. The cost distinction between the conventional and unconventional industries, however, has direct bearing upon the ability of the conventional industry to bear additional regulatory burdens. Further, the details as to cost and profitability inform as to what expenditures generate a worthy environmental return.

The well pad size difference discussed above is depicted in the following two photographs:

Unconventional Drilling Operation

Conventional Drilling Operation

The difference in formation pressure, production pressure and potential for flowback is reflected in the requisite pumping horsepower depicted in the following two photographs:

Unconventional Well Completion Fleet (hydrofracture)

Conventional Well Completion Truck (hydrofracture)

A topic that has frequently arisen in our panel discussions is the volume of produced product. As I noted in my comments submitted July 13, 2021, the typical conventional well in southwest Pennsylvania produces predominantly gas. First year production is expected to be approximately 12 million cubic feet; that translates to average production of 34,000 cubic feet per day. In comparison, production from a typical new shale well in Pennsylvania is expected to be approximately 5 million cubic feet per day (with some wells producing as much as 20 million cubic feet per day). The shale (unconventional) well gas volume is nearly 150 times greater than the gas volume of the conventional gas well.

The conventional wells located in northwest Pennsylvania produce primarily oil. Therefore, the gas volume from a new conventional oil well in northwestern Pennsylvania is even less than its conventional southwestern counterpart—approximately 14,000 cubic feet per day, well less than ½ of the gas production from a southwestern Pennsylvania conventional well, and 350 times less than an unconventional well.

Depletion takes a rapid toll on Pennsylvania conventional wells. As you examine the charts I provided in my comments submitted July 13, 2021, you will see that gas production declines 20 to 30% per year until the decline curve begins to flatten at years 4 to 5. You will recall that operators of Pennsylvania conventional wells submitted oil and gas production data to the state of Pennsylvania which shows cumulative conventional production for 2020 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. Thus, Pennsylvania average conventional well production is 0.61 BOE/day.

Conventional wells in New York State are very similar. Based upon 2019 production data on file with the NYSDEC the average conventional well production is 0.54 BOE/day.

The final significant difference between unconventional and conventional wells is the nature of the production equipment utilized to operate conventional wells. The model facilities used to create NSPS OOOOa assume the typical low production and marginal wellsite would have a similar complexity and fugitive equipment count (e.g., valves, flanges, connections, etc.) as much larger producing facilities. This is entirely incorrect, and this very significant difference requires additional focus.

There are over 100,000 conventional wells registered with the PADEP in Pennsylvania, with tens of thousands of those being predominantly oil wells located in the north, and, similarly, tens of thousands of predominantly gas wells located in the south. The predominantly oil wells are all simple facilities, generally fitting one of three configurations:

1) Pumping Unit. The majority of the predominantly oil wells consist of an above-ground well head and pump jack with below-ground tubing and rods. The pump jack operates the rods in an up and down motion to pump the oil to the well head. Two pipelines depart the well head, one carrying oil and one carrying natural gas. There are no other facilities or connections at the well site. The oil pipeline conveys oil from multiple wells to single or multiple oil collection tanks termed a tank battery. The gas pipeline conveys natural gas from multiple wells to a pipeline delivery point. Usually somewhere in that system the gas is conveyed through a separator to remove liquids and in some cases the gas is conveyed through a compressor to increase pressure at the delivery point. However, it should be

noted that many dozens or hundreds of wells might be served by a single separator, resulting in a far lower level of complexity and fugitive equipment count than that assumed in the EPA model facilities. The picture, below, depicts a typical pumping unit configuration.

2) Flow/Rabbit Facility: In this configuration the well head and tubing are present but the pump jack and rods are absent. If the production sandstone is of adequate gas pressure (a circumstance that exists in some new wells but generally lasts for only a few months), the pressure differential is utilized for a few minutes or hours per day to propel fluid via the tubing to the well head and collection tank; natural gas is separated from the fluid via a separator. During the remainder of the day natural gas is collected in the well head's second pipeline in fashion similar to configuration number one. Because most conventional wells have inadequate pressure to sustain such method of production the conventional industry employs the alternative method of a rabbit, which rabbit functions like a piston to move fluid in the tubing. A rabbit well is operated by intermittently shutting a production valve at the upper end of its production pipe to allow gas pressure in the well to build up. During such time the fluid accumulates above the rabbit which is at rest in the tubing near the bottom of the well. These fluids migrate upwards through the clearance between the rabbit and the inner walls of the tubing. At some point determined by a timer, or manually, the production valve is opened to the collection tank whereby pressure in the upper region of the tubing above the rabbit is reduced. The pressure differential above and below the rabbit causes the rabbit to rise in the tubing and thereby lift the fluids which are above the

rabbit. A well configured in this manner is similar to the picture above except that the pumpjack is not present.

3) Bailing Well: Wells that make insufficient fluid to justify the capital investment of a pumpjack, tubing and rods, are bailed to collect the fluid and to thereby stimulate improved natural gas production. A bailing well contains no below-ground equipment. At the surface is merely the well head and a single pipeline which conveys the natural gas. At some point (usually at intervals of months or years) a "bailing rig" is set up at the well location. The bailing rig lowers a cable into the well bore; secured at the end of the cable is a bailer which is a device that collects fluid. The bailer is lowered to the bottom of the hole, fluid enters the bailer, and the bailer is removed from the well bore; the fluid is then collected in a portable tank.

Configurations 1 and 2 are utilized in association with new conventional wells and are therefore directly relevant to the NSPS discussion underway. Configuration 3 is not associated with new conventional wells. However, the configuration may be relevant to the current discussion depending upon the EPA's treatment of a "modification".

Pennsylvania's (and New York State's) predominantly natural gas wells are also simple facilities, generally conforming to the "Flow/Rabbit Facility" described above. Swabbing is a variation of the "Flow/Rabbit Facility". During swabbing a service rig utilizes a steel cable to lower a rabbit-like device to the bottom of the tubing. As the service rig reels the device back to surface the fluid above the device is lifted out of the well bore. Below is a picture of a swabbing operation in southwest Pennsylvania.

The typical conventional oil well site in northwestern Pennsylvania and New York State would not normally include the following emission source types:

1) Glycol dehydrators
2) Amine gas sweetening units
3) Line heater, heater treater, reboilers
4) Gas compressors (a gas compressor, when in use, would typically be associated with a group of wells, not a single well)
5) Pneumatic controllers
6) Pneumatic pumps
7) Pipeline blowdowns

The typical conventional gas well also involves many fewer fugitive equipment items (valves, connections, etc.) than the models assumed by the EPA. The conventional gas well includes the well head (with no pumpjack). The gas pipeline is sometimes connected directly to the gas collection system. In other cases the pipeline is directed through a separator. In both cases there would normally be a meter installation. Some new conventional gas wells may have a line heater with a separator or a production unit (combination heater separator) early in well's life. As the well's pressure declines the line heater becomes unnecessary. Finally, wells in certain geographic areas may have a desiccant drier on the well site in lieu of a separator inasmuch as the drier will act as both a free water separator and a dehydrator, dehydrating by using calcium chloride pellets (no emissions).

Below is a photograph of a newly completed conventional gas well located in southwestern Pennsylvania. Visible are the well head, meter installation, and separator. The produced water tank is non-steel.

In contrast, below is a picture of infrastructure in place at a Pennsylvania Marcellus well pad:

The difference in physical qualities as between conventional wells on one hand, and unconventional wells on the other, is highly significant. The legislature of Pennsylvania has recognized that Pennsylvania's unconventional and conventional oil and gas industries are distinct and should be regulated separately. Act 52 of 2016 provides: "Any rulemaking concerning conventional oil and gas wells that the Environmental Quality Board undertakes after the effective date of this act shall be undertaken separately and independently of unconventional wells or other subjects and shall include a regulatory analysis form submitted to the Independent Regulatory Review Commission that is restricted to the subject of conventional oil and gas wells."

Similarly, the approach of the EPA should be a separate regulatory framework for conventional and unconventional wells. The conventional wells in Pennsylvania and New York State are configured in a manner significantly different than the models assumed by the EPA, namely models which assume elements consistent with an unconventional well configuration. The items of infrastructure and therefore the number of fugitive components (valves, flanges, connections, etc.) are qualitatively different as between conventional and unconventional wells. Similarly, the natural gas pressures are dozens of times, and flow volumes more than one hundred times, different as between unconventional wells and conventional wells. The combined factors of the number of components, the pressure contained by those components, and the amount of gas flowing through same, bear directly upon leak rates. That these factors result in very low leak rates at conventional wells is directly supported by the leak detection and repair (LDAR) monitoring examples discussed below.

2. LEAK DETECTION AND REPAIR (LDAR) MONITORING.

During the period of June 29 to July 14, 2021, IOGANY contracted Great Plains Analytical Services, Inc. (GAS) to conduct leak monitoring for New York State conventional gas well sites. GAS is a company that conducts LDAR monitoring nationwide for oil and gas operations. For the LDAR monitoring, GAS used its Standard Operating Procedures that conform with 40 CFR 60, Subpart OOOOa leak monitoring requirements.

To ensure a random selection of wells for onsite LDAR monitoring, an IOGANY representative built an Excel database of wells from three producers that consisted of 3,181 wells. The database included well name, County, Township, latitude, longitude, API# and BOE based on NYSDEC production records. A random number was assigned to each of the wells using the Excel random number generator function. An attorney (not affiliated with the producers) verified the list of wells and the random numbers generated. The list was sorted based on the number generated. The attorney chose to select the lowest 150 numbers to create the list of wells to be monitored.

A well operator accompanied the GAS optical gas imaging (OGI) camera surveyor team during the LDAR monitoring. There were no compressors at any of the facilities monitored. The following is a summary of the results:

- Number of gas well sites monitored: 150
- Total number of leaking components found: 22
- Total connectors leaking: 14
- Total valves leaking: 8
- Estimated component count for sites: 19,983
- Percent leak rate across all sites monitored for estimated component count: 0.11%

Although the OGI Camera used by GAS did not quantify the leaks, the OGI Camera Surveyor reported the leak volumes as minor based on the detected plume and cloud movement of leaking vapors visualized through the OGI Camera.

Leaks detected for 10 connectors and 5 valves were repaired the same day (or within 2 days) of LDAR monitoring and re-monitored with the OGI camera to verify repairs. Leaks that could not be repaired at the time were scheduled for repair within 30 days of discovery. Operators used the soap bubble test method to verify leak repair.

Appendix 1 contains more detailed results for the OGI camera survey conducted by GAS. GAS performed an actual count of valves operating at the facility. The estimated total number of other components (i.e., screwed connections) was determined for the typical well site and this count plus the valve count was used to estimate the total components count.

The operators who accompanied GAS and who performed the leak repairs also collected anecdotal information about the nature of the leaks. In particular, before repair, typical leaks detected by the OGI camera survey were tested via the soap bubble method. The soap bubble method demonstrated the existence of the leak; however, the soap bubbles also revealed that the leaks were very small, causing bubbles few in number and/or of small size. The small leaks were consistent with the low-pressure quality of the wells.

In addition to the monitoring performed by IOGANY a PGCC Committee member reported that extensive leak monitoring was undertaken by the Pennsylvania Department of Environmental Protection (PADEP) relative to 80 Pennsylvania conventional wells operated by the PGCC member.

Appendix 2 contains a summary of the results of the PADEP leak monitoring. It is observed that the PADEP inspector found no combustible gas detected at the well head and well area. These reports included 4 shut-in gas wells and 76 operating gas wells.

The inspector checked for combustible gases using an Altair 5 X Multi Gas Meter (photoionization detector). Although this monitoring was not following EPA Method 21 procedures, the reports do indicate that the Pennsylvania conventional wells have few leaking components.

3. REPORTING AND RECORDKEEPING

Pennsylvania bifurcates its oil and gas reporting requirements; a simple level of reporting (generally annual) pertains to conventional oil and gas operations; a significantly more complicated (and frequent) level of reporting is required for unconventional operations. At first glance, the EPA E-reporting template is similar to, or more complex than, the level of reporting required in Pennsylvania for unconventional oil and gas operations.

However, PGCC has not had time to dive into the details of the EPA E-reporting template. PGCC is an entirely volunteer organization. That volunteer status reflects the financial capabilities of the conventional industry that PGCC serves. The Pennsylvania conventional industry consists of sole proprietors and small companies that have small or no office staff. Cameron Energy is one of the larger conventional companies, and my wife is an unpaid "employee" who helps complete reports. Many other companies are literally mom and pops, and as I noted during our teleconference, some older conventional operators do not own a computer.

Pennsylvania's bifurcated reporting requirements also reflect the different qualities of the two industries. As noted above, the volume of oil and gas produced per well in Pennsylvania's unconventional industry is over one hundred times greater than the conventional industry. Accordingly, Pennsylvania's unconventional operators are required to report production on a monthly basis. Conventional operators report on an annual basis. Similarly, unconventional wells operate at pressures several dozen times greater than conventional wells and unconventional wells have many more components than conventional wells. Accordingly, the Pennsylvania Mechanical Well Integrity Report for unconventional operators is more detailed than the Report required for conventional operators.

As discussed below, PGCC's recommended solution at the federal level is to identify a subcategory which excludes low volume low pressure conventional wells from the NSPS rules under consideration. If that pathway is not followed then PGCC will need to find a volunteer who has time to examine the E-reporting template.

4. LIQUIDS UNLOADING

Pennsylvania and New York State liquids unloading in conventional wells generally requires a high velocity flow. The methods of tubing swabbing, rabbits (plunger lifts), casing swabbing and other methods depend upon venting, with no back pressure, to develop maximum velocity. Reduced velocity would equate to reduced effectiveness and likely increased cycles necessary to reduce liquid head pressures.

There is certainly no technology currently in use in New York State or Pennsylvania which would capture the emissions associated with the various methods of liquids unloading. The amount of gas emitted during these operations, is of course, dependent upon the age of well, availability of staff and thus frequency of the operation, and the like. The transit of a rabbit might occur several times per day or as infrequently as once per week. With each transit the amount of gas emitted is smaller than compared to a tubing or casing swab. A PGCC Committee member operating numerous conventional gas wells in southwestern Pennsylvania reports that swabbing is typically not required until somewhere between year 5 and year 10 of well operation. Thereafter, swabbing is performed on less frequent intervals because fluid production declines with the age of the southwestern Pennsylvania conventional well.

What can be universally said about the gas quantity from liquids unloading is that it is fundamentally limited by the low volume/low pressure nature of the well that is being unloaded, and in the case of swabbing, by the inherent infrequency of operations. In other words, even if one could collect or flare the emission, the amount emitted at a conventional well is fundamentally low, bringing into play the calculation of whether the cost of that recovery or flare is warranted.

Recovery might be technologically feasible with the modification of a vapor recovery system. However, the energy required to operate the vapor recovery system renders this theory impractical. First, taking into account the energy required to manufacture and operate the recovery systems, and taking into account the very low volume of gas involved with the conventional wells, it is highly unlikely that the energy recovered would exceed the energy expended. Therefore, the exercise of recovery itself would generate more emissions than it would recover. Second, the form of energy to operate the recovery system is electricity. Electricity is entirely unavailable at tens of thousands of well locations in Pennsylvania and New York and it is infeasible to make that electricity available (unless by generator—which of course involves yet another form of emission). Additional details about vapor recovery and electricity are provided, below, in the section pertaining to tanks.

Similarly, the technology to burn the emitted gas in the very short time it occurs, is not available. PGCC committee members did not have ideas for how such infrastructure might be invented or operated in a safe manner at a reasonable cost.

Again, economies of scale are at play in the difference between conventional and unconventional operations. While the per unit cost of recovery would not be warranted in a conventional well setting given the fundamentally small daily production of Pennsylvania and New York State conventional wells, the per unit cost of recovery at an unconventional well would be lower given that production is one hundred fifty times greater than a conventional gas well and 350 times lower than a conventional oil well, and given that unconventional wells are fewer in number and are more likely to be served by electricity (or be in closer proximity to an existing electrical source). Again, the model that treats conventional wells the same as unconventional wells is fundamentally flawed and will not result in a workable regulatory framework.

5. TANK BATTERIES

Five factors affecting control of emissions at conventional tank batteries have not been discussed in the SER panel discussions: 1) tank composition; 2) cost of oxygen monitoring; 3) unavailability of gas sales pipeline; 4) Intermittent gas generation; and 5) difficulty of powering the control infrastructure.

1) Tank Composition: At Pennsylvania and New York conventional well sites or tank batteries there exist tens of thousands of non-steel tanks. These tanks are typically made of a poly plastic or fiberglass material that operate at atmospheric pressure (i.e., no hatches or pressure/vacuum valves). These tanks are used both to receive fluids as directly produced from the well and to hold produced water that is separated after draining. Emissions from the latter would be minimal; however, emissions from the former are contemplated as part of our NSPS discussion. In either event, the non-steel tanks are not designed to hold any pressure. To control emissions the non-steel tank would need to be replaced with a suitably

equipped steel tank that is equipped with thief hatches and pressure/vacuum (e.g., Enardo). The material cost alone exceeds $6000 per tank and installation would roughly double that cost.

Additionally, tens of thousands of existing steel tanks are not sealed units and would require modifications. The modifications would be difficult because the tanks are not uniform. Indeed, at older tank batteries or wells, some tanks are converted from other uses and are of disparate manufacture, such as riveted tanks, and could not be modified at all. These existing tanks would fall within the orbit of the NSPS rules under discussion if a new well were connected to the existing tank battery or if an adjacent tank was replaced.

Depicted below is a typical conventional New York State gas well serviced by poly tank:

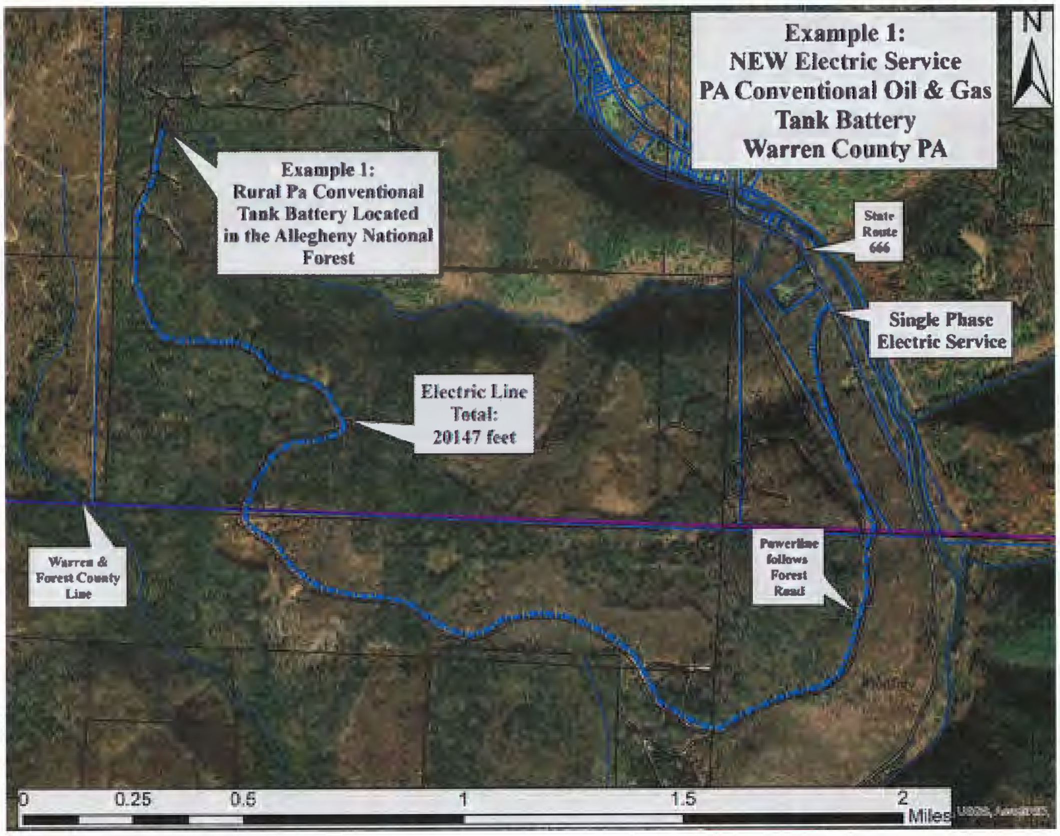
2) Cost of Oxygen Monitoring: any vapor recovery unit would require simultaneous installation of methods/technologies to prevent oxygen (air) from entering the storage vent gas collected by the vapor recover unity. Failure to detect oxygen in the natural gas would result in an explosive mixture and could not be permitted in any part of the collection system. The oxygen monitoring adds to cost and complexity of the facility.

3) Pipeline Availability: Not all tank batteries are adjacent to natural gas pipeline facilities and in those circumstances a flare or enclosed combustor would be required. This would be especially problematic in the intermittent pumping situations discussed immediately below.

4) Intermittent Well Operations: In Pennsylvania and New York State conventional operations the flow to tanks is intermittent. For example, the wells producing predominantly oil are pumped at intervals ranging from once per week to once per day. The pumping times range from a few minutes to a few hours. During the majority of the day, at the majority of the tank batteries, there are no material emissions from the tanks because there is no flow to the tanks. Consequently, there is no fuel for a flare or enclosed combustor; if the tank emissions were the source of fuel to power a generator to operate a vapor recovery unit, the generator would not function full time and would require manual attendance at each cycling. Similarly, flow to tanks at conventional gas wells occurs intermittently, sometime in concert with the cycling of a rabbit or in other instances only when sufficient fluid is accumulated in a separator. In the latter instance the fluid flow might be for a mere matter of seconds, and it would be impossible to capture associated emissions.

5) Electricity: Conventional operations in Pennsylvania and New York often occur in remote areas not served by electricity. The photograph above, depicting the New York State conventional gas well, is typical of a location not served by electricity. Similarly, tens of thousands of oil wells are operated by internal combustion engines (ice) due to the unavailability of electricity. Below is a photograph of such an ice well.

Forest County Pennsylvania is typical of the problem. Forest County is home to 5713 active conventional oil and gas wells. Forest County is sparsely populated, with approximately 3000 full time residents. The Allegheny National Forest covers over 90% of the County meaning roads are few and electrical service is non-existent in those areas. Even where electrical service is available in the County, it is primarily single-phase, meaning it is not suitable to provide power over long distances. The map, below, depicts one of Cameron Energy's several tank battery locations in Forest County, not serviced by electricity.



Roughly four miles of electric line would need to be installed to service the tank battery. However, the available service is only single phase; the resulting amperage at the destination would be only approximately 3 amps, which would not be sufficient to operate a vapor recovery unit. Therefore, one or more transformers would also be required, thus adding to the cost. The cost for electrical service, alone, would be $128,000. (See Appendix 3 for multiple examples.) Total gas sales from the tank battery in 2020 were $3,435. Gas sales from vapor recovery would obviously be substantially less than that amount. The costs of installation and operation of the electric service and vapor recovery unit would never be recoverable. This tank battery location is an area where Cameron is drilling new oil wells and is thus relevant to our NSPS discussion.

6. APPLICATION OF REGULATORY FRAMEWORK

There has not been adequate time in our panel discussions to flesh out when a new or modified item such as a tank or compressor would fall within the regulatory framework. For example, with respect to tanks, a new conventional oil well would, in most instances, be connected to an existing collection system, meaning that the produced oil would be collected at an existing tank battery. If there is a risk that the additional production would cause emissions at the tank battery to exceed 6 tpy, the prudent conventional operator would either not drill the well or suffer the cost (and environmental disturbance) of establishing a new/separate tank battery. Assuming the well is drilled and the new tank is constructed, the emissions, nevertheless, would be the same as if the more efficient connection was made to the existing tank.

This points to the latent problem with the OOOOa regulations in general, and the NSPS discussion in particular, namely, that the emission regulations have been crafted from the outset with large unconventional shale wells in mind. A new shale well is going to be connected to a tank facility where the emissions will either be greater or lesser than 6 tpy and there are no discretionary layout alternatives that will change that proposition. In the context of the conventional wells the operator is put to the Hobson's choice of doing what is sensible (connecting efficiently to the existing tank battery) or avoiding the OOOOa problem by creating a new tank battery—with the ultimate emissions being the same in either event. This is yet another argument for the wisdom of creating a sub-category which excludes conventional wells from the regulation.

The same considerations apply to the replacement of a compressor. Often times compressors are changed because production is declining and the attendant risk of emissions is therefore declining in step with the production. Nevertheless, if the replaced compressor is regarded as a modification which triggers the application of the regulation, the expensive burden of the regulatory framework descends upon the operator. The operator would be better off to continue to operate the inefficient compressor, burning more fuel, and bringing the wells to an earlier termination than if the compressor was resized.

7. PLACING THE CONVENTIONAL WELL LDAR "PROBLEM" IN CONTEXT

Understanding the scope of the conventional well "problem" 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 to 11% of U.S. production. Therefore, the emissions from the low production wells are in the 0.10 to 0.20% range of the GHGI.

Nationally, low production wells average about 2.5 to 2.7 barrels per day if they are oil wells and 22 to 24 mcf if they are natural gas wells. The average Pennsylvania and New York State conventional wells produce about 1/5 of the national average. The potential for problematic emissions in Pennsylvania and New York State is not present and therefore the predicate for imposing a new regulatory framework does not exist.

Nevertheless, this panel process is underway in contemplation that Pennsylvania and New York State conventional operators will have to comply with NSPS LDAR requirements that EPA acknowledges are very costly. As one compares the financial information I provided in my July 13, 2021 comments, with the per well site costs projected by the EPA for LDAR compliance, it is obvious that the NSPS LDAR requirements put Pennsylvania and New York State conventional operators in serious economic jeopardy. Indeed, in some cases, the cost of site compliance is greater than site revenue. EPA recognized this reality when it did not impose the 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.

It is of deep concern that the EPA is moving forward without reliable data appropriate to identify the emissions profile of low production wells. The U.S. Department of Energy (DOE) has initiated a study of emissions from low production wells and that study is now just a few months from completion. Preliminary results indicate no quantifiable or measurable emissions from low production wells or tank facilities. Indeed, preliminary results are revealing that the top 10% emission sources contribute roughly 3/4 of the total measured emissions.

Low production conventional wells do not have the well pressure or flow rate to be top 10% emission sources, nor could they come anywhere close to that, even if the conventional wells were beset by rampant negligence. But negligent care is not the norm. Life in the conventional oil and gas patch is hardscrabble, and leaks represent a loss of precious revenue. Meaningful leaks are not hard to detect. A conventional operator can smell or hear a meaningful leak. The soap bubble testing done in New York State confirms that a $100,000 detection device is $99,999 of overkill. Conventional operators in Pennsylvania and New York State already have ample incentive to address emissions and the test results cited herein demonstrate the effectiveness of the care the conventional operators have given. You will recall that the IOGANY testing was random; the Pennsylvania testing was performed without advance notice to the operator. The preliminary results of the DOE study are consistent with the Pennsylvania and New York State test results. In short, the EPA has not shown that in Pennsylvania and New York State there is a problem to be solved with conventional oil and gas wells.

8. ESTABLISHING A SUBCATEGORY THAT EXCLUDES CONVENTIONAL WELLS

Performance Standards (NSPS) fugitive emissions regulations created a specific problem for low producing conventional wells like those in Pennsylvania and New York State. When EPA developed its fugitive emissions requirements, it generated its Best System of Emissions Reductions (BSER) technology based on large, hydraulically fractured unconventional wells, and its initial proposal applied only to those unconventional wells. However, in finalizing the fugitive emissions regulations, EPA expanded their scope to include low production wells, but EPA never revised the BSER requirements to reflect this broader application.

The EPA heard much feedback that 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 provided an off-ramp when well sites fall below 15 barrels/day.

Now there appears to be a change in policy underway that is deaf to the concerns that were raised and addressed by the off-ramp. Once again, merely because conventional and unconventional wells produce the same or similar products, the differences between the two industries are being forgotten or ignored. In the panel discussions the EPA intimates that the off-ramp is being closed and that conventional wells are to be swept into the same regulatory framework as unconventional wells. Yet the two industries are different. To regulate two wells in the same fashion, where one produces 150 times more than the other and operates at many dozens of times greater pressure, is nonsensical.

A significant body of information supports the exclusion of conventional wells from the regulatory framework. The emission testing cited above demonstrates that, in the conventional context, the emissions problem is not qualitatively widespread, and that where an emission is occurring the quantity is small. The pictures included herein show the lack of fugitive emission components. The information presented herein and addressed at our panel discussions demonstrates that the expenditures required for emission control yield very little return in the conventional context. This is a simple reflection of the fact that the emissions are small and that any effort to collect them is expensive in context.

The solution is to exclude conventional wells from the regulatory framework. A simple and tested means of accomplishing that exclusion is to continue the stripper well exception, with the threshold for stripper wells being understood to be 15 BOE/day.

In the panel discussions the EPA has been unable to commit to that exclusion and has asked for other means of subcategorization. I offer the following:

1) Utilize alternative EPA Stripper Well threshold of 10 barrels per day. The threshold of 10 barrels per day is found at subpart F of 40 CFR Part 435. The EPA brought this CFR section to the attention of PGCC several years ago in association with a new rule promulgated by the EPA prohibiting discharge of onshore "unconventional oil and gas" (UOG) wastewaters to publicly owned treatment works (POTWs). By its own admission in its scoping documents, the EPA did not intend for its new rule to prohibit treatment of wastewater from "conventional" wells at POTW's. However, in the final iteration of the Rule the EPA defined a UOG as "crude oil and natural gas produced by a well drilled into a shale and/or tight formation (including, but not limited to, shale gas, shale oil, tight gas, and tight oil". That definition was different than the definition used in the scoping documents; in particular, the final definition removed the phrase "low porosity, low permeability" formation from the definition.

   The new definition expanded a UOG well to include what Pennsylvania defines as conventional wells. This is the source of my remark during our teleconference, that in the view of the EPA, Drake's well in Titusville is an unconventional well.

   PGCC brought legal action to prevent the implementation of the new rule and definition as to Pennsylvania conventional wells. Ultimately, that suit was resolved satisfactorily, when the EPA determined that, under subpart F, the new rule would not apply to "stripper wells" meaning wells producing less than 10 barrels per day. Because PGCC member wells produce less than 10 barrels per day, PGCC members were and are able to continue to deliver wastewater to POTWs.

   Interestingly, PGCC and EPA did not arrive at a satisfactory result via the clarification of the definition of a UOG. Therefore, I have grave reservations about the efficacy of the definition of "hydraulic fracturing" as set out in the EPA supplemental materials reviewed at our July 29 and August 3 meetings. That definition relies upon "tight formations", the same term that gave rise to the controversy in the POTW matter. Without more, the term "tight" is far too ambiguous to distinguish between what all of us would agree is an unconventional well and what, for example, Pennsylvania law defines as a conventional well.

   The threshold of 10 BOE/day is a compromise amount that may address whatever reservations the EPA has about continuing with the 15 BOE/day threshold. It is also an amount that effectively excludes Pennsylvania and New York State conventional wells, inasmuch as those wells produce 15 times less than that threshold amount.

2) Categorize by well bore direction. In Pennsylvania and New York State conventional wells are almost entirely vertical well bores. Where horizontal well bores have been attempted the hoped-for goal is the achievement of production far greater than a vertical conventional well. If that goal is achieved, the resulting additional production may lead to additional emissions befitting the regulatory framework and/or revenue that yields a reasonable per unit cost for the implementation of emission control measures. PGCC supports a regulatory approach which excludes vertical well bores from the regulatory framework. (Some conventional wells deviate from vertical at the surface in order to pass under streams, wetlands, and similar features. These "slant" well bores then become vertical wells as the well bore passes through the producing formations. The important distinction is the bore direction at the producing formation depths.)

3) Categorization by hydrofracture size. In Pennsylvania and New York State most new conventional wells are hydrofractured. However, those hydrofractures are designed for the high permeability, low production, low pressure formations that are the target of the conventional industry. The conventional hydrofractures are qualitatively different than the high volume, high pressure hydrofractures that are necessary to the completion of unconventional shale wells. Therefore, identifying the qualities that are unique to each industry's different hydrofractures would be an effective means of categorizing the two industries and excluding the hydrofractured conventional wells from inclusion in the NSPS regulations.

   Factors that distinguish the two types of hydrofractures include the following:
   a) Fluid volume
   b) Pumping pressures
   c) Shut-in pressures
   d) Permeability of fractured formations
   e) Flowback rates and times

   The PGCC committee members were reluctant to provide specific volume, pressure, Darcie and flowback suggestions without consulting all PGCC members. There has not been enough certainty of information or adequate time to conduct a PGCC member survey. However, it can be confidently said that the differences in volume, pressures, Darcie and flowback are very significant—in all cases at least 10 to 100 times different, and in some cases 1000's of times different as between the two industries—such that the categorization of hydrofracture size would be an effective, useful means of subcategorization.

Sincerely,

Arthur Stewart
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APPENDIX 1

Appendix 1. Independent Oil & Gas Association of New York (IOGANY) LDAR Monitoring

LDAR monitoring conducted by: Great Plains Analytical Services, Inc., 303 W. 3rd St. Elk City, OK 73644; www.gasinc.us

Item	Monitoring Date	Company	Facility/Well Name	Well API #	County	Facility Latitude	Facility Longitude	Facility Valve Count	Est. Facility Total Component Count	No. Leaking Components Found	Specify Component Types Leaking	Date Leaking Components Repaired
1	6/30/2021	Empire	CHYLINSKI #179	31-013-11000	CHAUTAUQUA	42.19189	-79.68599	15	120	1	Connector	7/1/2021
2	7/13/2021	Empire	FARNER-ZOAR VALLEY #1 #162	31-009-12459	CATTARAUGUS	42.45647	-78.8096	14	112	1	Connector	Scheduled 30 days from discover date
3	7/7/2021	Empire	FARRAR, WILLIAM #086	31-013-10878	CHAUTAUQUA	42.33573	-79.45288	24	192	1	Connector	7/1/2021
4	6/30/2021	Empire	HARRINGTON, A. #2	31-013-16976	CHAUTAUQUA	42.25955	-79.5287	16	128	1	Connector	7/1/2021
5	6/30/2021	Empire	NYSRA 5-23	31-013-16713	CHAUTAUQUA	42.23768	-79.58223	15	120	1	Connector	7/1/2021
6	7/7/2021	Empire	RININGER, T. #1	31-013-16454	CHAUTAUQUA	42.03955	-79.21566	10	80	1	Connector	7/7/2021
7	7/1/2021	Empire	SNELL, WILLIS #060	31-013-10460	CHAUTAUQUA	42.36246	-79.3754	16	128	1	Connector	7/1/2021
8	7/1/2021	Empire	STANTON, CLIFFSTAR #1 #152	31-013-10660	CHAUTAUQUA	42.4236	-79.39146	13	104	1	Connector	7/1/2021
9	7/1/2021	Empire	VILLAGE OF BROCTON #299	31-013-11711	CHAUTAUQUA	42.35931	-79.41608	27	216	1	Connector	7/1/2021
10	7/14/2021	Empire	WATERMAN UNIT #1 #318	31-013-12103	CHAUTAUQUA	42.46521	-79.14822	21	168	1	Connector	Scheduled 30 days from discover date
11	7/13/2021	Minard Run	KELLER 2H	31-053-26057-00-00	MADISON	42.742486	-75.620252	22	178	1	Connector	7/13/2021
12	7/14/2021	Stedman	ARNDT 1	31-029-16605	ERIE	42.84123	-78.5941	9	90	1	Connector	7/14/2021
13	7/8/2021	Stedman	BARTON 2	31-009-18280	CATTARAUGUS	42.1208	-79.03594	21	210	1	Connector	Scheduled 30 days from discover date
14	7/8/2021	Stedman	LOOMIS 1	31-009-17990	CATTARAUGUS	42.11887	-79.04911	26	260	1	Connector	Scheduled 30 days from discover date
15	7/1/2021	Empire	KINGSMITH FARM INC. #525	31-013-12611	CHAUTAUQUA	42.2634	-79.39327	25	200	1	Valve	7/1/2021
16	7/8/2021	Empire	LAMPSON/MCKAY #1	31-009-22318	CATTARAUGUS	42.27358	-79.02026	24	192	1	Valve	7/9/2021
17	7/7/2021	Empire	NORDLAND, J. #2	31-013-16620	CHAUTAUQUA	42.01254	-79.15536	9	72	1	Valve	7/9/2021
18	7/14/2021	Minard Run	JENSON 1247	31-099-21404-00-00	SENECA	42.883989	-76.898948	23	179	1	Valve	Scheduled 30 days from discover date
19	6/29/2021	Stedman	KELWASKI 1	31-013-24512	CHAUTAUQUA	42.159443	-79.65629	22	220	1	Valve	6/29/2021
20	7/14/2021	Stedman	KUTTER 3	31-037-23022	GENESEE	42.99582	-78.42084	12	120	1	Valve	Scheduled 30 days from discover date
21	7/12/2021	Stedman	NYSRA 1-1	31-013-15692	CHAUTAUQUA	42.27926	-79.15172	20	200	1	Valve	Scheduled 30 days from discover date
22	7/14/2021	Stedman	PARKS 2	31-037-23082	GENESEE	43.0161	-78.43665	7	70	1	Valve	7/14/2021
23	7/13/2021	Empire	ALLEN #1	31-009-23336	CATTARAUGUS	42.3862	-78.94571	8	64	0	N/A	N/A
24	6/30/2021	Empire	BABCOCK, DALE #130	31-013-10177	CHAUTAUQUA	42.23837	-79.65768	17	136	0	N/A	N/A

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Item	Monitoring Date	Company	Facility/Well Name	Well API #	County	Facility Latitude	Facility Longitude	Facility Valve Count	Est. Facility Total Component Count	No. Leaking Components Found	Specify Component Types Leaking	Date Leaking Components Repaired
25	7/13/2021	Empire	BAIRD #2	31-009-16423	CATTARAUGUS	42.3521	-78.93384	6	48	0	N/A	N/A
26	7/8/2021	Empire	BARRETT, C. #2	31-009-18287	CATTARAUGUS	42.21224	-79.05252	12	96	0	N/A	N/A
27	7/14/2021	Empire	BECKER, A. #1 #308	31-013-12093	CHAUTAUQUA	42.47855	-79.15231	16	128	0	N/A	N/A
28	7/12/2021	Empire	BEIGHTOL L. #5	31-013-18303	CHAUTAUQUA	42.19148	-79.16647	9	72	0	N/A	N/A
29	6/30/2021	Empire	BERBEN, L. #1	31-013-18547	CHAUTAUQUA	42.20735	-79.55389	7	56	0	N/A	N/A
30	7/13/2021	Empire	BERGEY, D #1	31-009-17276	CATTARAUGUS	42.35072	-78.96106	15	120	0	N/A	N/A
31	6/30/2021	Empire	BERTRAM, JOYCE #127	31-013-12597	CHAUTAUQUA	42.27557	-79.50384	13	104	0	N/A	N/A
32	7/13/2021	Empire	BEVIER #1233-I	31-029-14900	ERIE	42.54035	-78.86728	10	80	0	N/A	N/A
33	7/14/2021	Empire	BIRGE #1838-I	31-037-02924	GENESEE	42.97703	-78.45826	9	72	0	N/A	N/A
34	6/30/2021	Empire	BOEHM, M. #2	31-013-15251	CHAUTAUQUA	42.22674	-79.53512	11	88	0	N/A	N/A
35	7/1/2021	Empire	BOWEN, CALVIN #219	31-013-11063	CHAUTAUQUA	42.24827	-79.63546	13	104	0	N/A	N/A
36	7/13/2021	Empire	BOWERS #4	31-009-23284	CATTARAUGUS	42.39717	-78.92313	8	64	0	N/A	N/A
37	7/7/2021	Empire	BROWN, G. #3	31-009-17161	CATTARAUGUS	42.17168	-79.03338	5	40	0	N/A	N/A
38	7/14/2021	Empire	BURKE, D. #1	31-029-22066	ERIE	42.67553	-79.02043	17	136	0	N/A	N/A
39	6/30/2021	Empire	CALDWELL #2	31-013-13218	CHAUTAUQUA	42.29227	-79.67264	7	56	0	N/A	N/A
40	7/13/2021	Empire	CARLSEN, A #1	31-029-22471	ERIE	42.54874	-78.52074	16	128	0	N/A	N/A
41	7/14/2021	Empire	CHERRY #1 #279	31-013-11783	CHAUTAUQUA	42.48163	-79.3086	12	96	0	N/A	N/A
42	6/30/2021	Empire	CLOVERBANK #1	31-013-15180	CHAUTAUQUA	42.20097	-79.55921	14	112	0	N/A	N/A
43	6/30/2021	Empire	COLEMAN, H. #4	31-013-20763	CHAUTAUQUA	42.19161	-79.47651	17	136	0	N/A	N/A
44	7/7/2021	Empire	EDWARDS, I. #1 KA167	31-013-17861	CHAUTAUQUA	42.04557	-79.52448	12	96	0	N/A	N/A
45	7/1/2021	Empire	FARVER UNIT #1 #248	31-013-12131	CHAUTAUQUA	42.38345	-79.41387	13	104	0	N/A	N/A
46	7/14/2021	Empire	FOSS UNIT #2 #420	31-029-13096	ERIE	42.71953	-78.51726	11	88	0	N/A	N/A
47	7/13/2021	Empire	FRANK, J. #2	31-009-17175	CATTARAUGUS	42.33386	-78.67938	10	80	0	N/A	N/A
48	7/13/2021	Empire	GARDINER #1	31-009-18077	CATTARAUGUS	42.37644	-78.86385	8	64	0	N/A	N/A
49	6/29/2021	Empire	GEHR #740	31-013-18142	CHAUTAUQUA	42.14307	-79.66502	18	144	0	N/A	N/A
50	7/14/2021	Empire	HECHT, G. #3 #411	31-029-12419	ERIE	42.59219	-79.1175	16	128	0	N/A	N/A
51	7/12/2021	Empire	HERSHBERGER, JOHN UNIT #1 KP	31-009-19103	CATTARAUGUS	42.22806	-78.98416	7	56	0	N/A	N/A
52	7/13/2021	Empire	HOSKINS UNIT #1	31-029-22175	ERIE	42.55911	-78.70396	16	128	0	N/A	N/A
53	7/12/2021	Empire	HOSTETLER 1	31-009-25504	CATTARAUGUS	42.248349	-79.011115	9	72	0	N/A	N/A
54	7/12/2021	Empire	JENKS, GERTRUDE #1 KX008	31-009-17147	CATTARAUGUS	42.19588	-78.9785	19	152	0	N/A	N/A
55	7/13/2021	Empire	KOTA, F #1	31-009-16929	CATTARAUGUS	42.42836	-78.93404	7	56	0	N/A	N/A
56	7/7/2021	Empire	KUREK, EDWARD UNIT #2 KX021	31-009-17949	CATTARAUGUS	42.17718	-79.01214	4	32	0	N/A	N/A
57	6/29/2021	Empire	LICTUS, V. #1	31-013-16007	CHAUTAUQUA	42.00624	-79.63328	18	144	0	N/A	N/A
58	6/30/2021	Empire	LIMBERG, D. #1	31-013-15344	CHAUTAUQUA	42.17984	-79.48589	13	104	0	N/A	N/A

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Item	Monitoring Date	Company	Facility/Well Name	Well API #	County	Facility Latitude	Facility Longitude	Facility Valve Count	Est. Facility Total Component Count	No. Leaking Components Found	Specify Component Types Leaking	Date Leaking Components Repaired
59	7/14/2021	Empire	LOTT, R&S. UNIT #1	31-099-23112	SENECA	42.882707	-76.805275	19	152	0	N/A	N/A
60	7/14/2021	Empire	LUTHERAN SOCIETY #1	31-029-22273	ERIE	42.81043	-78.69292	24	192	0	N/A	N/A
61	6/29/2021	Empire	LYONS, R. #2 CB150	31-013-22615	CHAUTAUQUA	42.05512	-79.54483	21	168	0	N/A	N/A
62	6/30/2021	Empire	MARTINSON, P. #1	31-013-16356	CHAUTAUQUA	42.17008	-79.55669	19	152	0	N/A	N/A
63	6/30/2021	Empire	MEEDER, ANDY #183	31-013-10705	CHAUTAUQUA	42.18988	-79.66013	21	168	0	N/A	N/A
64	7/8/2021	Empire	MILLER, E.I. #1	31-009-22449	CATTARAUGUS	42.29277	-79.03489	21	168	0	N/A	N/A
65	7/8/2021	Empire	MILLER, I. #1	31-009-16784	CATTARAUGUS	42.2969	-79.03308	12	96	0	N/A	N/A
66	6/30/2021	Empire	MOORE, J. #1	31-013-14314	CHAUTAUQUA	42.2766	-79.73808	9	72	0	N/A	N/A
67	7/1/2021	Empire	NIXON, A. #2	31-013-14300	CHAUTAUQUA	42.29544	-79.60309	10	80	0	N/A	N/A
68	7/12/2021	Empire	NORD N. #1	31-013-18122	CHAUTAUQUA	42.18196	-79.10582	18	144	0	N/A	N/A
69	7/1/2021	Empire	NYHART, LYLE #056	31-013-10299	CHAUTAUQUA	42.36048	-79.33164	12	96	0	N/A	N/A
70	7/12/2021	Empire	NYSRA #10-1636	31-013-15357	CHAUTAUQUA	42.24184	-79.22955	14	112	0	N/A	N/A
71	6/30/2021	Empire	NYSRA #2-1289	31-013-14880	CHAUTAUQUA	42.10525	-79.49464	16	128	0	N/A	N/A
72	7/12/2021	Empire	OLMSTEAD, H. #1	31-013-15418	CHAUTAUQUA	42.20523	-79.22658	17	136	0	N/A	N/A
73	7/7/2021	Empire	ONOFRIO, JAMES #296	31-013-11671	CHAUTAUQUA	42.31029	-79.42343	20	160	0	N/A	N/A
74	7/13/2021	Empire	PLOETZ, E. #3	31-009-16961	CATTARAUGUS	42.36282	-78.66036	10	80	0	N/A	N/A
75	6/30/2021	Empire	PROPHETER, EARLENE #552	31-013-13760	CHAUTAUQUA	42.26745	-79.56428	16	128	0	N/A	N/A
76	6/29/2021	Empire	REITZ #715	31-013-18306	CHAUTAUQUA	42.09934	-79.69114	23	184	0	N/A	N/A
77	6/30/2021	Empire	RICE, M. #3	31-013-18259	CHAUTAUQUA	42.17597	-79.45117	14	112	0	N/A	N/A
78	7/13/2021	Empire	RODERICK, EMILY O. #1-A #3	31-029-12403	ERIE	42.53549	-78.51061	8	64	0	N/A	N/A
79	6/29/2021	Empire	ROUSH, H. #2	31-013-19068	CHAUTAUQUA	42.01724	-79.62353	21	168	0	N/A	N/A
80	7/13/2021	Empire	SALISBURY, M #4	31-009-22055	CATTARAUGUS	42.36021	-78.87274	12	96	0	N/A	N/A
81	7/14/2021	Empire	SAMS & SONS, A. #1 #337	31-013-12170	CHAUTAUQUA	42.4588	-79.37866	14	112	0	N/A	N/A
82	7/14/2021	Empire	SCHMIDT, BLITZER #1	31-029-22418	ERIE	43.00487	-78.47961	16	128	0	N/A	N/A
83	7/1/2021	Empire	SCHUSTER UNIT #1	31-013-22526	CHAUTAUQUA	42.29618	-79.57808	22	176	0	N/A	N/A
84	7/7/2021	Empire	SHERMAN, W.J. #1	31-013-13976	CHAUTAUQUA	42.0739	-79.34085	17	136	0	N/A	N/A
85	7/13/2021	Empire	SHETLER, E #5	31-009-22039	CATTARAUGUS	42.35424	-78.97517	12	96	0	N/A	N/A
86	7/12/2021	Empire	SHETLER, LEWIS UNIT #1 KA123	31-009-17093	CATTARAUGUS	42.24085	-78.98213	17	136	0	N/A	N/A
87	7/7/2021	Empire	SHOEMAKER, JACK #307	31-013-11316	CHAUTAUQUA	42.32486	-79.42106	15	120	0	N/A	N/A
88	7/12/2021	Empire	SHORT, G. #1	31-013-19292	CHAUTAUQUA	42.16125	-79.13976	14	112	0	N/A	N/A
89	7/7/2021	Empire	SINGER-SETSER #7334	31-013-21770	CHAUTAUQUA	42.00451	-79.36443	18	144	0	N/A	N/A
90	7/12/2021	Empire	SKILLMAN, N. #2	31-013-19210	CHAUTAUQUA	42.16934	-79.35508	17	136	0	N/A	N/A
91	7/14/2021	Empire	SMITH-GRIGGS #2	31-099-23041	SENECA	42.981519	-76.847799	19	152	0	N/A	N/A
92	7/8/2021	Empire	SOBIERAJ #1	31-009-22342	CATTARAUGUS	42.2788	-79.02944	16	128	0	N/A	N/A

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93	7/12/2021	Empire	SPRAGUE, R. #1	31-013-21154	CHAUTAUQUA	42.17415	-79.163	13	104	0	N/A	N/A
94	7/12/2021	Empire	SPRAGUE, R. #2	31-013-21183	CHAUTAUQUA	42.14376	-79.17349	25	200	0	N/A	N/A
95	7/13/2021	Empire	STEARNS #265-I	31-029-68454	ERIE	42.53815	-78.83457	12	96	0	N/A	N/A
96	7/14/2021	Empire	STEELE #1 #(38472)	31-069-26153	ONTARIO	42.888204	-77.445536	15	120	0	N/A	N/A
97	7/13/2021	Empire	STEWART, R. #1	31-013-19704	CHAUTAUQUA	42.43777	-79.10925	9	72	0	N/A	N/A
98	7/12/2021	Empire	STONE, ROBERT #1 KX012	31-009-17267	CATTARAUGUS	42.18392	-78.97694	19	152	0	N/A	N/A
99	7/13/2021	Empire	VAN ETTEN, C 4	31-009-23486	CATTARAUGUS	42.37561	-78.97659	9	72	0	N/A	N/A
100	6/29/2021	Empire	VOLK, MURRAY #111	31-013-10250	CHAUTAUQUA	42.16012	-79.66939	14	112	0	N/A	N/A
101	7/1/2021	Empire	WEISE #2	31-013-22516	CHAUTAUQUA	42.30163	-79.48772	13	104	0	N/A	N/A
102	6/30/2021	Empire	WELLS, C. #1	31-013-20910	CHAUTAUQUA	42.17203	-79.44921	20	160	0	N/A	N/A
103	7/1/2021	Empire	WHEELER, ETHEL J. #1 #171	31-013-04948	CHAUTAUQUA	42.3873	-79.38811	17	136	0	N/A	N/A
104	6/29/2021	Empire	WHITE, D. #1A	31-013-17667	CHAUTAUQUA	42.05076	-79.65577	9	72	0	N/A	N/A
105	7/14/2021	Empire	WHITE, H&G. UNIT #1 #37	31-013-12308	CHAUTAUQUA	42.47056	-79.14332	14	112	0	N/A	N/A
106	6/30/2021	Empire	WILCOX, R. #1	31-013-15342	CHAUTAUQUA	42.22705	-79.51831	19	152	0	N/A	N/A
107	7/8/2021	Empire	YODER, L. #1	31-009-22269	CATTARAUGUS	42.28518	-79.04047	14	112	0	N/A	N/A
108	7/13/2021	Minard Run	BLASI 1-H	31-017-26018-00-00	CHENANGO	42.648838	-75.641504	17	167	0	N/A	N/A
109	7/13/2021	Minard Run	BLOOD 1	31-017-26049-00-00	CHENANGO	42.534655	-75.643197	38	190	0	N/A	N/A
110	7/13/2021	Minard Run	DROMGOOLE 6-498	31-053-23870-00-00	MADISON	42.760633	-75.621469	15	171	0	N/A	N/A
111	7/14/2021	Minard Run	FREIER 1 (626015)	31-099-23937-00-00	SENECA	42.81898	-76.91344	23	181	0	N/A	N/A
112	7/14/2021	Minard Run	HARTMAN 624594	31-099-22947-00-00	SENECA	42.8475	-76.862831	21	173	0	N/A	N/A
113	7/14/2021	Minard Run	JELLINGHAUSE 975-6	31-011-21238-00-00	CAYUGA	42.880884	-76.659369	10	162	0	N/A	N/A
114	7/14/2021	Minard Run	JORDAN 1233	31-011-21361-00-00	CAYUGA	42.822698	-76.660466	26	182	0	N/A	N/A
115	7/14/2021	Minard Run	KIDD 2513	31-099-19414-00-00	SENECA	42.842792	-76.864407	21	175	0	N/A	N/A
116	7/14/2021	Minard Run	LOCKWOOD 1078-2	31-011-20647-00-00	CAYUGA	42.909675	-76.627696	17	171	0	N/A	N/A
117	7/14/2021	Minard Run	LOTT 624600	31-099-22944-00-00	SENECA	42.879692	-76.812171	15	171	0	N/A	N/A
118	7/14/2021	Minard Run	O'HARA 1 (626943)	31-011-26167-00-00	CAYUGA	42.885995	-76.637353	25	183	0	N/A	N/A
119	7/13/2021	Minard Run	PARTEKO 3H	31-053-26159-00-00	MADISON	42.814676	-75.645428	17	175	0	N/A	N/A
120	7/14/2021	Minard Run	QUILL (CASLER)420-4	31-011-19637-00-00	CAYUGA	42.933672	-76.710002	14	166	0	N/A	N/A
121	7/14/2021	Minard Run	RASMUSSEN 624597	31-099-22959-00-00	SENECA	42.82297	-76.868404	21	179	0	N/A	N/A
122	7/14/2021	Minard Run	SCHENCK 2 (626404)	31-011-26004-00-00	CAYUGA	42.818251	-76.656732	22	178	0	N/A	N/A
123	7/14/2021	Minard Run	SHANK 952-4	31-011-20561-00-00	CAYUGA	42.89529	-76.65031	16	170	0	N/A	N/A
124	7/14/2021	Minard Run	SORENSEN 1 (4119)	31-099-19580-00-00	SENECA	42.817479	-76.900422	18	172	0	N/A	N/A
125	7/14/2021	Minard Run	STAEHR 1039-3	31-011-20614-00-00	CAYUGA	42.86217	-76.67724	23	179	0	N/A	N/A
126	7/14/2021	Minard Run	STAHL 1	31-099-11618-00-00	SENECA	42.838418	-76.788827	19	177	0	N/A	N/A

Appendix 1. Independent Oil & Gas Association of New York (IOGANY) LDAR Monitoring

LDAR monitoring conducted by: Great Plains Analytical Services, Inc., 303 W. 3rd St. Elk City, OK 73644; www.gasinc.us

Item	Monitoring Date	Company	Facility/Well Name	Well API #	County	Facility Latitude	Facility Longitude	Facility Valve Count	Est. Facility Total Component Count	No. Leaking Components Found	Specify Component Types Leaking	Date Leaking Components Repaired
127	7/14/2021	Stedman	ARK 3	31-013-25519	CHAUTAUQUA	42.532808	-79.200885	16	160	0	N/A	N/A
128	7/14/2021	Stedman	ARRIGO/NOTARO 1	31-029-20738	ERIE	42.60361	-79.02022	12	120	0	N/A	N/A
129	6/29/2021	Stedman	BALDWIN 1	31-013-25486	CHAUTAUQUA	42.072161	-79.499891	22	220	0	N/A	N/A
130	7/14/2021	Stedman	BAUDER 1	31-029-15425	ERIE	42.82464	-78.5682	13	130	0	N/A	N/A
131	6/29/2021	Stedman	COCHRAN WN1644	31-013-12805	CHAUTAUQUA	42.06982	-79.59679	18	180	0	N/A	N/A
132	7/14/2021	Stedman	CUMMINGS 3	31-037-23229	GENESEE	43.02212	-78.43102	14	140	0	N/A	N/A
133	7/14/2021	Stedman	DAWSON TANNER 1	31-121-13277	WYOMING	42.53701	-78.40613	11	110	0	N/A	N/A
134	6/29/2021	Stedman	EDDY 2	31-013-20404	CHAUTAUQUA	42.05722	-79.5209	29	290	0	N/A	N/A
135	7/8/2021	Stedman	FISHER UNIT 1	31-009-17018	CATTARAUGUS	42.11956	-78.95865	14	140	0	N/A	N/A
136	7/14/2021	Stedman	JEWITT 1	31-029-14435	ERIE	42.65487	-79.00545	8	80	0	N/A	N/A
137	7/12/2021	Stedman	JOHNSON, B 1	31-013-18825	CHAUTAUQUA	42.26444	-79.14571	17	170	0	N/A	N/A
138	7/14/2021	Stedman	KAPPUS 1	31-029-19717	ERIE	42.68932	-78.90587	6	60	0	N/A	N/A
139	7/1/2021	Stedman	LOWN 3A	31-013-18404	CHAUTAUQUA	42.17374	-79.38077	15	150	0	N/A	N/A
140	7/8/2021	Stedman	MEADE 1	31-009-16723	CATTARAUGUS	42.112	-79.03195	17	170	0	N/A	N/A
141	7/8/2021	Stedman	MOSHER-PARKER UNIT 1	31-009-19745	CATTARAUGUS	42.11074	-79.04346	18	180	0	N/A	N/A
142	6/29/2021	Stedman	NYSRA 4-2	31-013-12578	CHAUTAUQUA	42.044	-79.49336	13	130	0	N/A	N/A
143	7/1/2021	Stedman	NYSRA 6-3	31-013-16237	CHAUTAUQUA	42.28027	-79.40854	21	210	0	N/A	N/A
144	7/1/2021	Stedman	NYSRA 6-4	31-013-16309	CHAUTAUQUA	42.27374	-79.38311	22	220	0	N/A	N/A
145	7/14/2021	Stedman	PASCHKE 1	31-029-19968	ERIE	42.89489	-78.60515	10	100	0	N/A	N/A
146	7/14/2021	Stedman	PILLER 2	31-029-18678	ERIE	42.61787	-78.88231	14	140	0	N/A	N/A
147	6/29/2021	Stedman	ROCKY 3161	31-013-14792	CHAUTAUQUA	42.06563	-79.52502	21	210	0	N/A	N/A
148	7/8/2021	Stedman	SWEENEY, W. SR. 2	31-013-17970	CHAUTAUQUA	42.00782	-79.3564	15	150	0	N/A	N/A
149	7/14/2021	Stedman	TORRELLI 1	31-029-24575	ERIE	42.982251	-78.520648	13	130	0	N/A	N/A
150	7/14/2021	Stedman	ZILLIOX 1	31-121-19164	WYOMING	42.53771	-78.36208	12	120	0	N/A	N/A
								2339	19983	22		
									Percent Leakers - All Components:	0.11%		
									Percent Leakers - Valves:	0.34%		

N/A = Not Applicable

APPENDIX 2

Appendix 2 - Combustible Gas Monitoring

Item	Date	API #	Classification	MCF/Month	Barrels Oil/Month	Number of Compressors	Combustible Gas Detected?
1	5/24/2021	37-105-21099	Gas Well Shutin	0	0	0	0
2	5/24/2021	37-105-21098	Gas Well Shutin	0	0	0	0
3	5/24/2021	37-105-21239	Gas Well Shutin	0	0	0	0
4	6/8/2021	37-105-21339	Gas Well	67	0	0	0
5	6/8/2021	37-105-21338	Gas Well	245	0	0	0
6	6/8/2021	37-105-21340	Gas Well	86	0	0	0
7	6/21/2021	37-105-21475	Gas Well	11	0	0	0
8	6/21/2021	37-105-21474	Gas Well	47	0	0	0
9	6/21/2021	37-105-21473	Gas Well	105	0	0	0
10	6/21/2021	37-105-21327	Gas Well	114	0	0	0
11	6/21/2021	37-105-21329	Gas Well	101	0	0	0
12	6/21/2021	37-105-21328	Gas Well	84	0	0	0
13	6/21/2021	37-105-21217	Gas Well	140	0	0	0
14	6/22/2021	37-105-21345	Gas Well	324	0	0	0
15	6/22/2021	37-105-21086	Gas Well	165	0	0	0
16	6/28/2021	37-105-21331	Gas Well	205	0	0	0
17	6/28/2021	37-105-21095	Gas Well	186	0	0	0
18	6/28/2021	37-105-21219	Gas Well	79	0	0	0
19	6/28/2021	37-105-21306	Gas Well	184	0	0	0
20	6/28/2021	37-105-21304	Gas Well	52	0	0	0
21	6/28/2021	37-105-21218	Gas Well	29	0	0	0
22	6/28/2021	37-105-21346	Gas Well	97	0	0	0
23	6/29/2021	37-105-21200	Gas Well	22	0	0	0
24	6/29/2021	37-105-21094	Gas Well	171	0	0	0
25	6/29/2021	37-105-21321	Gas Well	31	0	0	0
26	6/29/2021	37-105-21275	Gas Well	80	0	0	0
27	6/29/2021	37-105-21130	Gas Well	71	0	0	0
28	6/29/2021	37-105-21132	Gas Well	33	0	0	0
29	6/29/2021	37-105-21319	Gas Well	Shut in	0	0	0
30	6/29/2021	37-105-21320	Gas Well	Shut in	0	0	0
31	6/29/2021	37-105-21486	Gas Well	8	0	0	0
32	6/29/2021	37-105-21305	Gas Well	91	0	0	0
33	6/29/2021	37-105-21210	Gas Well	69	0	0	0
34	6/29/2021	37-105-21211	Gas Well	147	0	0	0
35	6/29/2021	37-105-21087	Gas Well	2	0	0	0
36	6/29/2021	37-105-21201	Gas Well	26	0	0	0
37	6/29/2021	37-105-21208	Gas Well	68	0	0	0
38	6/29/2021	37-105-2119	Gas Well	Shut in	0	0	0
39	6/30/2021	37-105-21221	Gas Well	248	0	0	0
40	6/30/2021	37-105-21093	Gas Well	167	0	0	0
41	6/30/2021	37-105-21203	Gas Well	24	0	0	0
42	6/30/2021	37-105-21202	Gas Well	14	0	0	0
43	6/30/2021	37-105-21311	Gas Well	12	0	0	0
44	6/30/2021	37-105-21204	Gas Well	20	0	0	0
45	6/30/2021	37-105-21205	Gas Well	48	0	0	0
46	6/30/2021	37-105-21310	Gas Well	89	0	0	0
47	6/30/2021	37-105-21309	Gas Well	91	0	0	0
48	6/30/2021	37-105-21207	Gas Well	66	0	0	0
49	6/30/2021	37-105-21206	Gas Well	130	0	0	0
50	7/6/2021	37-105-21316	Gas Well	130	0	0	0

Appendix 2 - Combustible Gas Monitoring

Item	Date	API #	Classification	MCF/Month	Barrels Oil/Month	Number of Compressors	Combustible Gas Detected?
51	7/6/2021	37-105-21326	Gas Well	69	0	0	0
52	7/6/2021	37-105-21235	Gas Well	22	0	0	0
53	7/6/2021	37-105-21236	Gas Well	4	0	0	0
54	7/7/2021	37-105-21472	Gas Well	175	0	0	0
55	7/7/2021	37-105-21314	Gas Well	116	0	0	0
56	7/7/2021	37-105-21476	Gas Well	116	0	0	0
57	7/7/2021	37-105-21303	Gas Well	12	0	0	0
58	7/7/2021	37-105-21347	Gas Well	69	0	0	0
59	7/7/2021	37-105-21317	Gas Well	87	0	0	0
60	7/7/2021	37-105-21315	Gas Well	54	0	0	0
61	7/7/2021	37-105-21505	Gas Well	91	0	0	0
62	7/7/2021	37-105-21222	Gas Well	114	0	0	0
63	7/7/2021	37-105-21220	Gas Well	88	0	0	0
64	7/7/2021	37-105-21325	Gas Well	57	0	0	0
65	7/7/2021	37-105-21313	Gas Well	204	0	0	0
66	7/7/2021	37-105-21223	Gas Well	119	0	0	0
67	7/7/2021	37-105-21308	Gas Well	48	0	0	0
68	7/7/2021	37-105-21322	Gas Well	192	0	0	0
69	7/7/2021	37-105-21214	Gas Well	341	0	0	0
70	7/8/2021	37-105-21324	Gas Well	140	0	0	0
71	7/8/2021	37-105-21332	Gas Well	98	0	0	0
72	7/8/2021	37-105-21312	Gas Well	31	0	0	0
73	7/8/2021	37-105-21212	Gas Well	107	0	0	0
74	7/8/2021	37-105-21216	Gas Well	Shut-in	0	0	0
75	7/8/2021	37-105-21215	Gas Well	107	0	0	0
76	7/8/2021	37-105-21318	Gas Well	215	0	0	0
77	7/8/2021	37-105-21213	Gas Well	119	0	0	0
78	7/8/2021	37-105-21085	Gas Well	9	0	0	0
79	7/8/2021	37-105-21489	Gas Well	117	0	0	0
80	7/8/2021	37-105-21307	Gas Well	170	0	0	0

This wellhead assembly and all fittings and connecting lines were checked for combustible gas detection with an Altair 5 X Multi Gas Meter

APPENDIX 3

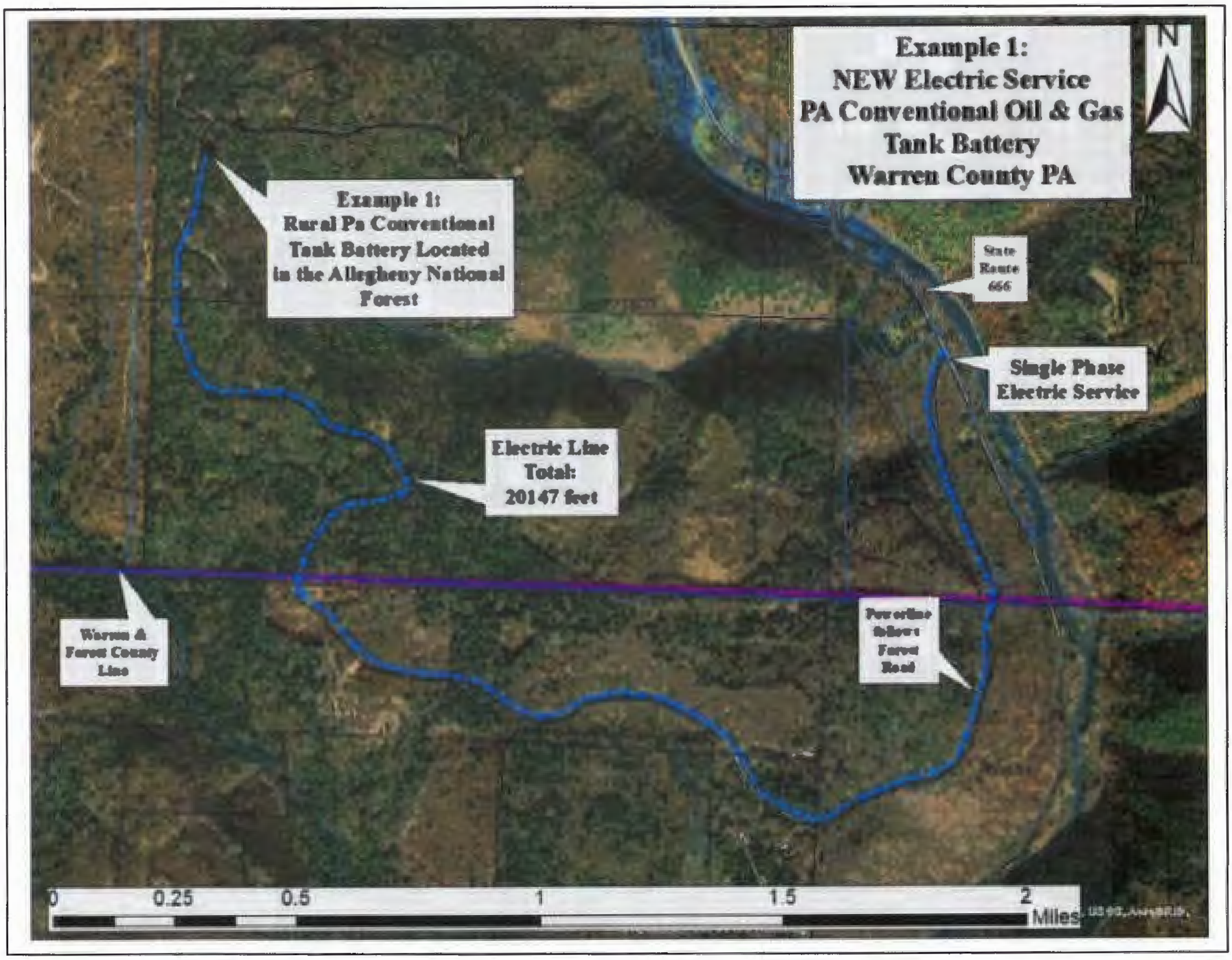
APPENDIX 3

Four Examples of Tank Batteries With No Electrical Service

Price quotation obtained from Hull Electric Warren, Pennsylvania August 9, 2021:

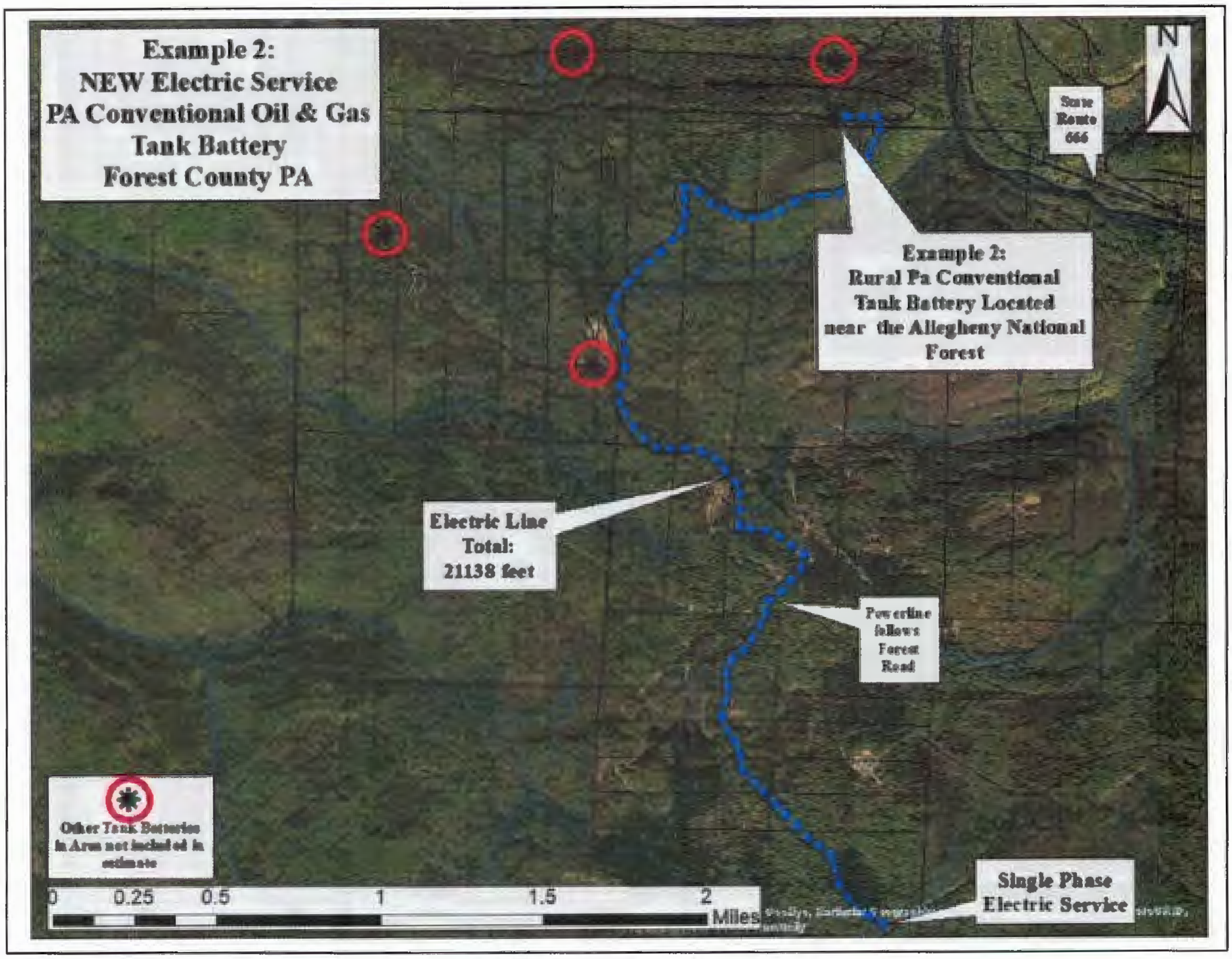
1.) Above Ground Power Line:
   a. 0000 Single Phase (1,000ft spools) - $2.85/ft
   b. 0000 Three Phase (1,000ft spools) - $3.60/ft
2.) Fuse Box Disconnect: (2 at each example):
   a. Single Phase - $375.00/each
   b. Three Phase - $525.00/each
3.) Power Poles (assume power pole every 200ft) - $350.00/each
4.) Power Pole Hook-up materials (assume 1 each of the following at every power pole):
   a. Wedge Clamps - $5.58/each
   b. Isolators - $8.63/each
   c. Wire Hangers - $8.75/each
5.) Miscellaneous Connection materials:
   a. Wire Connectors -$15.50/each (1 connector every 1,000 feet)
   b. Electric Meter - $60.00/each (1 at each example)
6.) 480 volt booster transformer - $6,750/each (1 at each new single phase service connection)
7.) Estimate New Service Connection by Local Electric Company - $2,500 at each point
   (*includes new pole, and service transformer*)
8.) Estimate of Labor to install new electric lines/service - $1,800 per day
   (*includes travel time, fuel, three man crew, electric connetion points and 1,600 ft line set*)

Example 1 – Cost $128,023.08



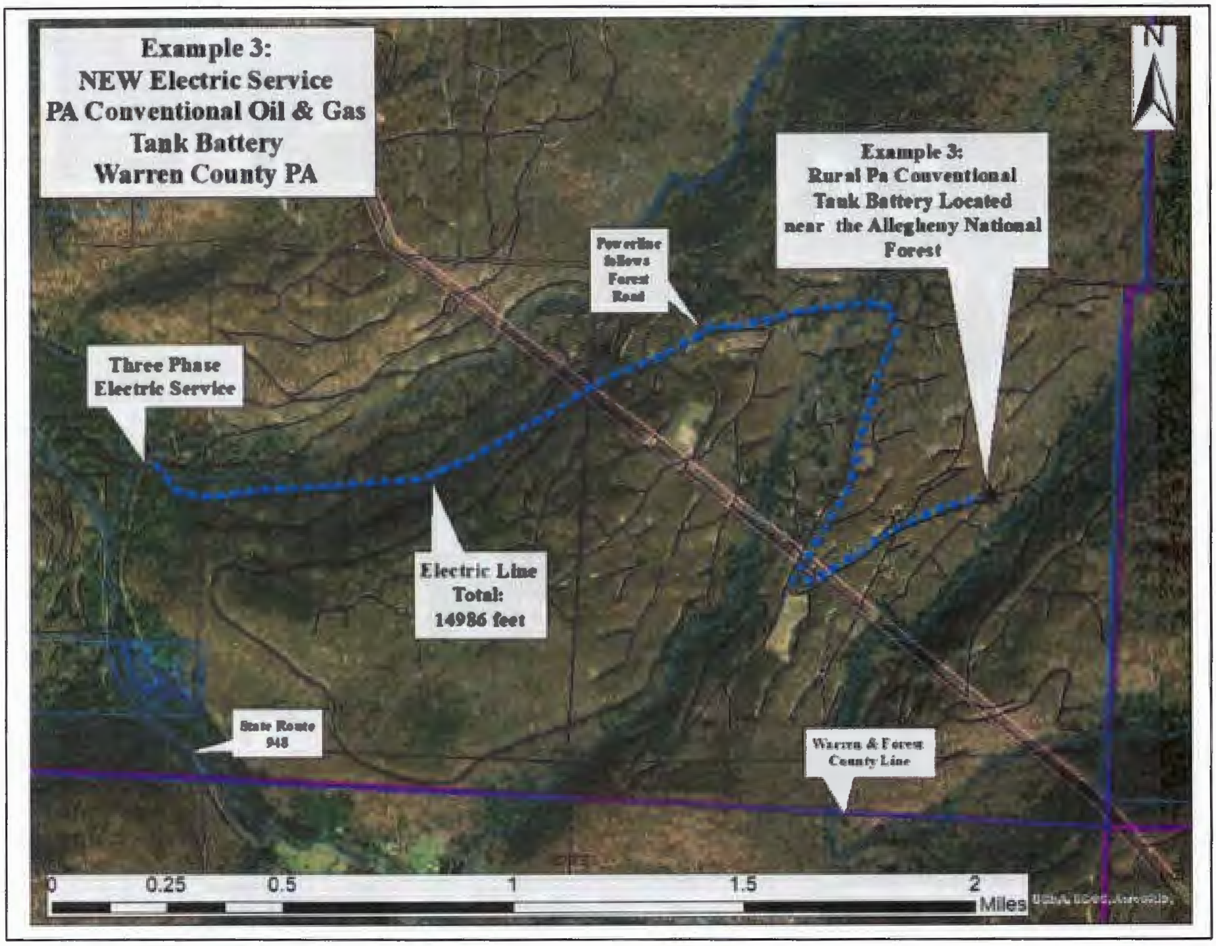
Example 1 Single Phase Electric--20,147 foot project: Estimated cost for installing new electric service is **$128,023.08** assuming 12.59 days of work. Project requires booster transformer to compensate for single phase service.

Example 2 – Cost $133,696.55



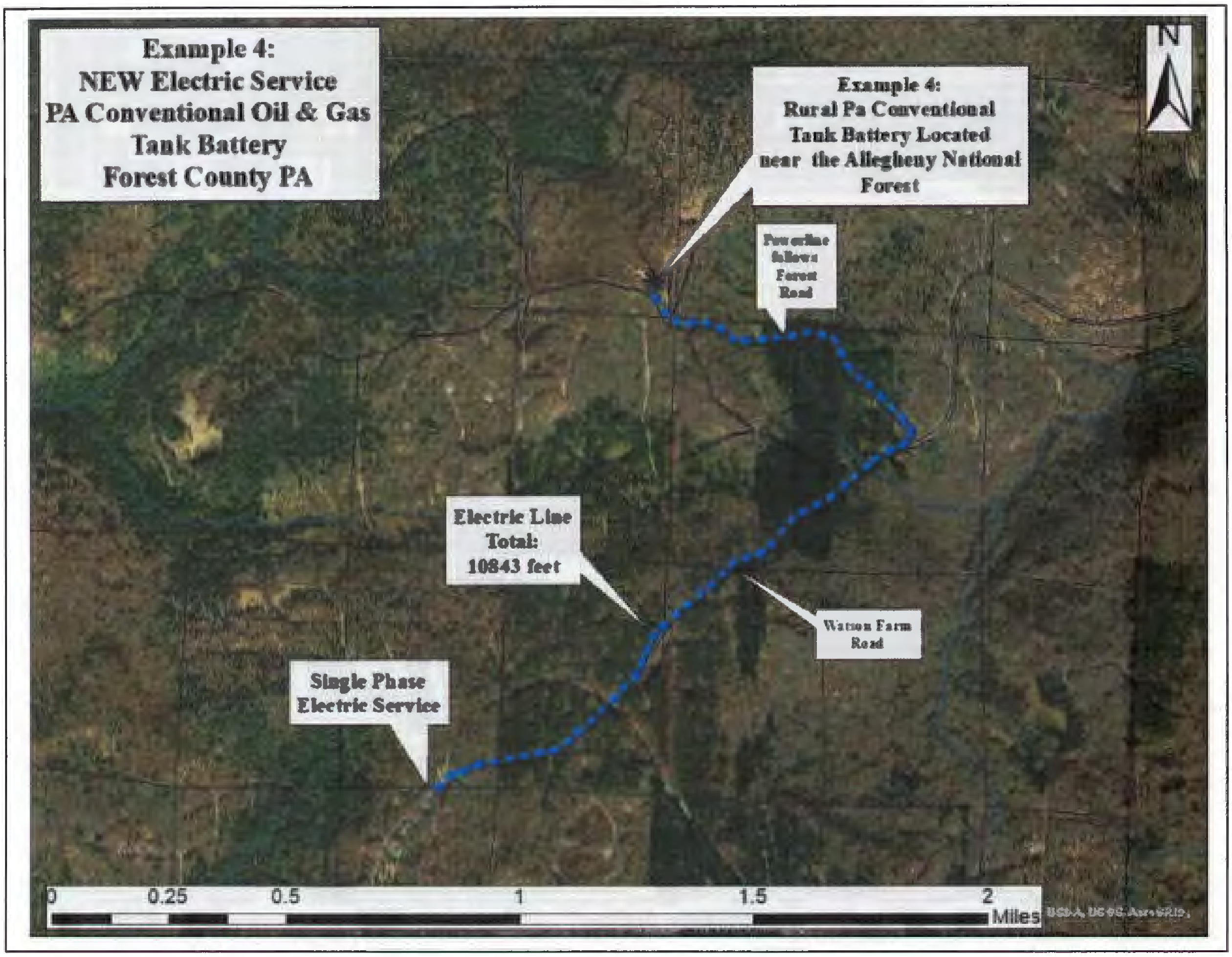
Example 2 Single Phase Electric--21,138 foot project: Forest County, Pennsylvania. Estimated cost for installing new electric service is **$133,696.55** assuming 13.21 days of work. This total does not include the installation and cost of the methane collection device. Using a "voltage drop calculator" it is estimated to only have **2 AMPs** of usable power at the end of the run; booster transformer therefore required.

Example 3 – Cost $103,265.85



Example 3 Three Phase Electric--14,986 foot project: Warren County, Pennsylvania. Estimated cost for installing new electric service is **$103,265.85** assuming 9.36 days of work. This total does not include the installation and cost of the methane collection device. Using a "voltage drop calculator" it is estimated to only have **6 AMPs** of usable power at the end of the run; booster transformer therefore required.

Example 4 – Cost $74,757.68



Example 4 Single Phase Electric--10,843 foot project: Forest County, Pennsylvania. The estimated cost for installing new electric service is **$74,757.68** assuming 6.77 days of work. This total does not include the installation and cost of the methane collection device. Using a "voltage drop calculator" it is estimated to only have **7 AMPs** of usable power at the end of the run; booster transformer required.

James D. Elliott
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jelliott@spilmanlaw.com

August 12, 2021

Lanelle Wiggins
U.S. Environmental Protection Agency
Office of Policy
1200 Pennsylvania Avenue, N.W.
Washington, DC 20460

VIA E-MAIL

Re: SER Comments to Oil and Natural Gas NSPS to SBAR Panel

Dear Ms. Wiggins,

The following comments are submitted on behalf of the Gas and Oil Association of WV, Inc. (GO-WV), the Independent Petroleum Association of America (IPAA) and Texas Independent Producers and Royalty Owners Association (TIPRO). Representatives of GO-WV, IPAA and TIPRO served as Small Entity Representatives (SERs) in the Small Business Advocacy Review Panel Process (SBAR Process) participating in the Pre-Panel Outreach Meeting on June 29, 2021; Panel Outreach Meeting on July 29, 2021 (SBAR Panel), and submitting certain comments after the June meeting. These comments are in response to information provided during both meetings. GO-WV, IPAA, and TIPRO appreciate the opportunity to serve as SERs, hopefully reducing the economic impact of the revisions to Subpart OOOO and/or Subpart OOOOa. A significant number or GO-WV, IPAA and TIPRO members not only qualify as "small entities" under the Regulatory Flexibility Act, but would also be characterized as "mom and pop" or family businesses. It is these smaller businesses that stand to lose the most by the regulations to be proposed at the end of September.

GO-WV was formed in January 2021, through the merger of the West Virginia Oil and Natural Gas Association (WVONGA) and the Independent Oil and Gas Association of West Virginia, Inc. (IOGA). GO-WV is a statewide trade association that represents companies engaged in the extraction, production and delivery of natural gas and oil in West Virginia and those businesses that support these extraction, production, and transmission activities. GO-WV was formed to promote and protect all aspects of the West Virginia oil and natural gas industry while protecting and improving both the environment and business climate of West Virginia.

IPAA represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will be the most significantly affected by the actions resulting from this regulatory proposal. Independent producers drill about 90 percent of American oil and gas wells, produce 54 percent of American oil and produce 85 percent of American natural gas.

TIPRO is a trade association representing the interests of nearly 3,000 independent oil and natural gas producers and royalty owners throughout Texas. As one of the nation's largest statewide associations representing both independent producers and royalty owners, members include small businesses, the largest, publicly-traded independent producers, and mineral owners, estates, and trusts. TIPRO membership provides networking and educational forums, marketing opportunities, industry intelligence, and extensive legislative and regulatory resources. A large percentage of TIPRO members are dependent, either directly as an operator or indirectly as a royalty owner, on low production wells or conventional operations and the pending proposals will have particular significance to these members.

Summary of Key Points:

- EPA continues to lack emissions data on low production wells to support regulatory decisions – but more data is close at hand.
- Exploring subcategorization of sources is warranted, if not obligated, and perhaps represents the most appropriate means to protect the environment while permitting and supporting small business which support rural communities and our country's energy independence.
- Don't "fix" what is not broken/don't let "perfection" be the enemy of the good: EPA and the oil/gas industry have worked together for at least a decade on New Source Performance Standards (NSPS) focused on volatile organic compounds (VOCs) and/or methane emissions from the industry and progress has been made.

Wait on the Data:

TIPRO, IPAA, and GO-WV and many other "Independent Producers"[1] have worked with EPA since 2011 to help EPA better understand the oil and natural gas industry – with particular focus on the extraction and production segment of the industry. Subpart OOOO and Subpart OOOOa were driven by the technological advances in mid to late 2000s associated with high volume, hydraulically fractured oil and/or natural gas wells with horizontal legs and the potential emissions associated with the new technology. EPA defines "hydraulic fracturing" as "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." 40 CFR 60.5430. As defined, hydraulically fractured wells could be argued to include most if not all oil and natural gas wells drilled back to the mid-nineteenth century Drake Well on the banks of the Oil Creek in western Pennsylvania.

Given the broad range of "hydraulic fracturing" it is not an appropriate definition for distinguishing types of "affected facility[ies]" because both conventional and unconventional wells

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[1] The Independent Petroleum Association of America ("IPAA"), Domestic Energy Producers Alliance ("DEPA"), Eastern Kansas Oil & Gas Association ("EKOGA"), Illinois Oil & Gas Association ("IOGA"), Independent Oil and Gas Association of West Virginia, Inc. ("IOGA-WV"), Indiana Oil and Gas Association ("INOGA"), International Association of Drilling Contractors ("IADC"), Kansas Independent Oil & Gas Association ("KIOGA"), Kentucky Oil & Gas Association ("KOGA"), Michigan Oil and Gas Association ("MOGA"), National Stripper Well Association ("NSWA"), North Dakota Petroleum Council ("NDPC"), Ohio Oil and Gas Association ("OOGA"), The Petroleum Alliance of Oklahoma ("The Alliance"), Pennsylvania Independent Oil & Gas Association ("PIOGA"), Texas Alliance of Energy Producers ("Texas Alliance"), Texas Independent Producers & Royalty Owners Association ("TIPRO"), and West Virginia Oil and Natural Gas Association ("WVONGA") (collectively, "Independent Producers").

engage in hydraulic fracturing. GO-WV, IPAA, and TIPRO and the Independent Producers have worked with EPA from 2011 to explain the difference between "unconventional wells" and "conventional wells" and their respective operations/activities. Representatives from TIPRO, IPAA, and GO-WV were encouraged by the substantive conversations with the SBAR Panel regarding the differences between "conventional" and "unconventional" wells.

TIPRO, IPAA, GO-WV and others have consistently represented that "low production wells" should be exempt from Subpart OOOO/Subpart OOOOa. We believe that EPA has resisted this because it has no, or the wrong emissions data on low production wells. Environmental non-governmental-organizations (ENGOs) have submitted various "studies" attempting to show low production wells are a significant source of methane emissions and must be regulated. We believe those studies are flawed. In 2018, the Department of Energy (DOE) initiated a study to quantify emissions from low production/marginal wells. The COVID pandemic delayed the collection of data from various regions/basins, but the DOE has re-initiated its study and its results are due the end of 2021. We encourage EPA to wait for completion of the DOE's study.

While the current Administration has decreed that regulatory action to address emissions from the oil and natural gas industry must be proposed in September of 2021, the scope of those proposals is within EPA's discretion. There is no statutory deadline requiring EPA to regulate low production wells. There is no court ordered deadline requiring EPA to promulgate regulations on low production wells. There is no shortage of other opportunities to regulate emissions from the oil and natural gas industry that EPA can address in order to comply with the President's Executive Order requiring proposed regulatory action by the end of September. I t makes sense to wait, as more data on low production wells is around the corner.

This Administration and Congress' actions to reinstate regulation of methane from the oil and natural gas industry has placed many small businesses in a dangerous place. To avoid unnecessarily damaging them, the most prudent course of action is for EPA to effectively stay the relevant provisions of Subpart OOOOa as they pertain to low production wells pending the outcome of the DOE study. Once the DOE study is complete, EPA will have considerably more data on which to make informed policy decisions. The data necessary for EPA to make more informed regulatory decisions is not years away – it's a few months. To those within the DC Beltway, regulation of low production wells may not be of much concern. To the mom and pop/small businesses across the country, excessive regulation of low production wells could unnecessarily sound the death knell for many businesses that fuel the country's economy. EPA should wait on the data from the DOE.

<u>Subcategorization of Sources Makes Sense:</u>

As EPA acknowledged to the SERs in its "Supplemental Materials" in July 2021, "appropriate subcategorization" is an acceptable regulatory alternative that can "still accomplish the objectives of the Clean Air Act." As was discussed at length with the SBAR Panel, the definition of "hydraulic fracturing" encompasses both "conventional" and "unconventional wells." Admittedly, conventional wells are hydraulically fractured. However, the world changed when industry figured out how to make a steel pipe take a "righthand turn" thousands of feet below the earth's surface and run horizontally for up to a few miles. Conventional wells do not penetrate and produce from "tight formations, such as shale or coal formations." Conventional wells do not "require high rate, extended flowback . . .." Most conventional wells, being shorter and having a shorter profile in producing strata, produce methane a lower rates than horizontal, nonconventional wells. Conventional wells are simply different than unconventional wells.

Most importantly, from an environmental perspective, nonconventional and conventional wells' emissions profiles are different. The physics associated with conventional wells and unconventional wells is on a different scale. The hydraulic fracturing associated with conventional wells involves thousands of gallons of water – unconventional wells involve millions of gallons of water. The flowback period of those liquids for conventional wells is measured in terms of hours whereas unconventional well flowback is measured in weeks or months. This is explained by the permeability of the geological strata each type of well usually operates within. In terms of permeability, the Darcy scale essentially measures the ability of fluids to flow through rock. The permeability of the rock formations where conventional wells are drilled is statistically different than that of the rock where unconventional wells are drilled in to (permeability of conventional wells in the Illinois Basin is 0.01-0.5 Darcie; shale formations typically 0.0000000.1-0.00001 Darcie).

Recognizing that conventional wells tend to generate lower production, such low production wells are ripe for subcategorization and have tremendous potential to reduce the burden on small entities. If SERs were afforded a more realistic time frame to provide comments, appropriate parameters could be better defined and established. EPA has the ability (and we believe the obligation) to consider subcategorization in the rules scheduled for proposal in September. EPA can and should bifurcate its regulatory activity between low production wells, which require more study, and nonconventional wells, about which there is more information. We are disappointed that appears to be beyond consideration by EPA. SERs asked EPA multiple times during the two meetings whether there was anything requiring regulatory action by the end of September for the proposed methane regulations, and we were never given any justification for such quick action. We hope that EPA will take this opportunity to reconsider its haste in proposing regulations.

<u>Continue to Improve Existing Regulations – Don't Regress</u>:

- Low Production Wells: reinstating the applicability of the 2016 Subpart OOOOa regulations to low production wells is no more justified now than it was in 2016. As discussed above, EPA lacks sufficient emissions data to justify regulation of low production wells. More/better data is on its way. Emissions at low production wells are a function of various factors including but not limited to volumetric flow, pressure and component count. All these factors effectively reduce low production wells "potential to emit" (PTE) when compared to wells producing gas above the 15 BOE/day threshold. The 15 BOE/day threshold was borrowed from the IRS regulations for various reasons. In reality, the average "low production well" is significantly below 15 BOE/day, e.g. about 2.5 bbl/day and 22 mcfd. Based on the PTE alone, low production wells warrant different treatment and such differential treatment would have tremendous benefit to small businesses/entities. Preliminary information from the DOE study is also indicating that the majority of emissions from low production wells is coming from relatively few sources. For example, preliminary data from the DOE study indicates that, in the Appalachian Basin, the "top 10% of emission sources contributed 72% of the total measured emissions, and the top two emissions source alone accounted for 40%."[2] These sources/leakers are often referred to as fat tail" sources. These sources/leaks do not require sophisticated and expensive equipment to detect – one can generally see, hear and/or smell the leak upon arrival at the site. It is generally obvious that there is a problem, and the problem is generally obvious, e.g., a hatch is stuck open; there is a hole in a pipe or connection; or a tree fell on a piece of equipment and its emitting to the atmosphere. GO-WV, IPAA, TIPRO and Independent Producers have consistently argued that while EPA views methane as a pollutant, it is also our "product" and operators have a pure economic motivation to capture every molecule of methane that they can affordably recover. These fat-tail/super emitters do not only harm the environment, they also threaten the economic viability of many small businesses.

- Recordkeeping and Reporting: the 2020 revisions to recordkeeping and reporting were very beneficial. Inconsistencies between the 2016 regulations and 2020 revisions should be resolved in favor of the 2020 revisions. EPA acknowledged certain state recordkeeping and reporting as "equivalent" to Subpart OOOOa and provided some regulatory relief for operators in those states. Even in these states, though, EPA continues to require additional recordkeeping and reporting that provides little to no benefit to the environment. If a state's program is deemed equivalent to Subpart OOOOa, then nothing more should be required above what the state requires. Additionally, EPA should continue to evaluate ways to streamline recordkeeping and reporting that provides no/little environmental benefit while increasing the regulatory burden and cost on operators.
- "Wellhead Only" Exemption: operators appreciate EPA's efforts to reduce the regulatory burden on the industry by exempting "wellhead only" sources from certain requirements. TIPRO, IPAA, and GO-WV suggest that this exemption be re-evaluated to allow a drop-tank/"separator" at the well site. The drop-tank/separator is often necessary for safety and operational considerations while having minimal emissions. The benefit to small business of the wellhead only exemption would be greatly increased if the certain additional equipment would be permitted.
- Liquids Unloading: emissions associated with liquids unloading is being revisited by EPA. The emissions associated with these processes were evaluated in 2015-2016 during the promulgation of Subpart OOOOa. EPA ultimately concluded that the processes/practices associated with liquids unloading were too diverse and not well enough understood to promulgate regulations to control the emissions. GO-WV, IPAA, and TIPRO respectfully ask if anything has changed that warrant promulgation of controls now. SERs reported to EPA that the practices continue to be, essentially, "site-specific." A "one-size fits all" is inappropriate in terms of mandating a particular control strategy. By its very nature, liquids unloading is undertaken to remove liquids that are prohibiting gas from coming up the well and entering the gathering line. As soon as enough liquid is removed to allow the gas to flow again, the system is returned to "normal" and the gas is routed back to the product line. Releasing a certain amount of gas is inherent in the process. The equipment that would be required to capture the relatively small amount of gas would need to be brought on site, for a very limited time period, at a considerable cost. The change in flow and pressure during the unloading is highly variable

[2] See attached exhibit from DOE/GSI.

which often makes it technically infeasible to utilize control equipment to capture the gas. The physical characteristics associated with liquids unloading that made it impractical/uneconomical to promulgate regulations in 2015/2016 have not changed -- liquids unloading remains more of an art than a science.

GO-WV, IPAA, and TIPRO appreciate the opportunity to serve as SERs. While it understandable that EPA desires to implement the President's executive order by regulating all industry sources of methane, EPA should not apply an arbitrary deadline on low producers at the expense of small businesses and sound public policy. The extremely truncated SBAR Panel process still has the potential to benefit small businesses and TIPRO, IPAA, and GO-WV look forward to reviewing the final report to EPA. GO-WV, IPAA, and TIPRO acknowledge EPA's position that the "guidelines" for existing sources pursuant to Section 111(d) of the Clean Air Act do not directly regulate its members. TIPRO, IPAA, and GO-WV respectfully request that EPA see past the technicalities of certain aspects of the CAA; fulfill the intent of the Regulatory Flexibility Act; and engage the SBAR Panel process for the "guidelines" EPA intends to propose in September. All stakeholders and regulators understand and appreciate that the greatest impact to the oil and natural gas industry of directly regulating methane emissions is enabling EPA to regulate existing sources. One only need review the legal briefs by environmental interests seeking stays and emergency relief before the Court of Appeals for District of Columbia Circuit to understand that the direct regulation of methane by EPA is about EPA regulating existing sources. Regardless of what one calls the requirements EPA intends to promulgate pursuant to section 111(d) of the CAA, EPA is establishing the bar by which controls on existing source are measured and ultimately controlled. The impact of the section 111(d) "guidelines" on small entities clearly has the potential to dwarf the impact of the reconsideration rulemaking to Subpart OOOOa.

TIPRO, IPAA, and GO-WV look forward to working with EPA to promulgate regulations and/or guidelines that protect the environment while permitting small entities to making a significant contribution to America's energy independence.

Respectfully submitted,

SPILMAN THOMAS & BATTLE, PLLC

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DOE NETL: Methane Emissions Quantification

Quantification of Methane Emissions from Marginal (Low Production Rate) Oil and Natural Gas Wells

BACKGROUND

PROBLEM STATEMENT

There are more than 1.1 million oil and natural gas wells in the U.S., of which about 770,000 (~70%) are considered marginal. Debate continues among concerned stakeholders regarding whether marginal well sites should be subject to or exempt from fugitive emissions monitoring and associated leak detection and repair (LDAR) requirements.

PROJECT OBJECTIVE

Collect and evaluate representative, defensible and repeatable data and draw quantifiable conclusions on the extent of methane emissions from marginal wells across oil and gas producing regions of the U.S., and to compare these results to published data available on the emissions from non-marginal wells.

DATA SOURCE STATUS ASSESSMENT

Key data gaps were identified based on a thorough review of published sources and partially addressed by information derived from a broad survey of oil and gas well operators.

- **Literature Review.** Findings of previous studies indicate that existing site-level emissions measurements and "activity data" (i.e., related to operations) from previous studies largely underrepresent and are not enough to accurately characterize marginal well emissions.

representing over 86,000 sites across 29 basins in 23 states indicate that ***site characteristics most likely to relate to methane emissions*** include i) the *main product* generated at the site, ii) the *production rate* of oil and/or natural gas, iii) the "*size*" of the site defined in terms of the total equipment count (wells, tanks, separators, etc.), and iv) the *frequency of liquids unloadings*. Figure 1 depicts the geographic distribution of ***48 site categories*** distinguishing the variability of these factors, as represented in the results of the operator survey, where each color represents a unique category and similar (but distinct) colors visually represent more closely related categories.

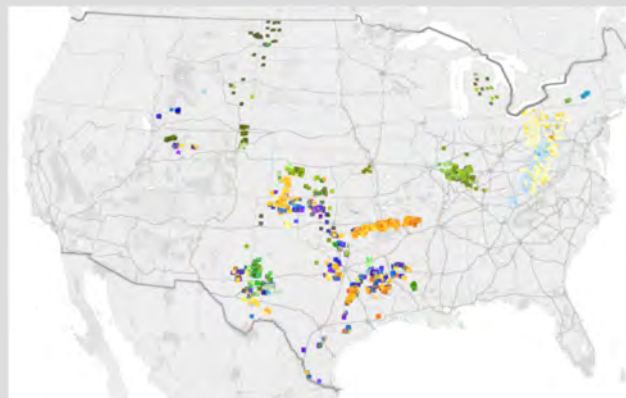

Figure 1. Marginal well sites represented in operator survey results

Sites primarily producing dry gas are shown in colors ranging from yellow to red, wet gas sites in purple/blue, and oil sites in shades of green. Within each product category, distinct colors represent differences in equipment count and production rate.

REGIONAL FIELD CAMPAIGNS

Field campaigns to detect, measure, and characterize oil and gas well site emissions are being performed in multiple regions/basins to capture the variability and diversity of both physical and operational conditions, especially in areas with large numbers or a high density of marginal wells, or where marginal wells account for a large percentage of regional production. Up to a 200 total well sites will be assessed within each of three field campaigns.

- **Field Campaign 1**. Completed in October-December 2019 in the *Appalachian, Illinois, and Forest City Basins*. The Appalachian Basin is largely dominated by natural gas production, whereas oil production is predominant in the Illinois, and Forest City Basins. Site populations in other regions are much more diverse and not well represented by sites in these basins.

- **Field Campaign 2**. Originally planned for April-May 2020 in the Permian and Anadarko Basins and postponed due to Covid-related travel and site access restrictions. Two weeks of field work in the *Upper Green River, Piceance, and Anadarko Basins* were completed in Nov 2020. Tentative plans call for additional sampling in the *Permian and Palo Duro Basins* in early 2021.

- **Field Campaign 3**. Tentatively planned for Spring 2021 to include additional coverage of the Rocky Mountains region, such as the *Uintah and Denver-Julesburg Basins*, and, if possible, *additional portions of the Permian and Anadarko Basins* not reachable in the second field campaign. Other regions may be studied, pending availability of site access.

There is broad consensus among scientists with DOE, EPA, industry, and environmental stakeholders that, due to the diversity and extensive geographic distribution of marginal wells across the U.S, there is a strong need for the full scope of the regional field campaigns to be carried out.

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FIELD CAMPAIGN 1 SUMMARY

■ **Visited Field Sites.** Facilities were selected for measurement using *geographically clustered, random sampling*. Escorted access to sites was provided by participating host operators, whose identities and site locations remain confidential, per signed access agreements.

146 natural gas sites and 87 oil sites were visited. In all, 228 of the sites exhibited marginal production at an average rate of 2.5 BOE per day of combined oil and gas. Five non-marginal sites producing 96 MCFD (16 BOE/day, "marginally non-marginal") to 4,000 MCFD (667 BOE/day) of dry gas were visited in the Appalachian Basin. No non-marginal oil production sites were available in any of the visited regions. Besides emissions screening and measurements, *detailed activity data*, including major equipment counts and oil and gas production rates,

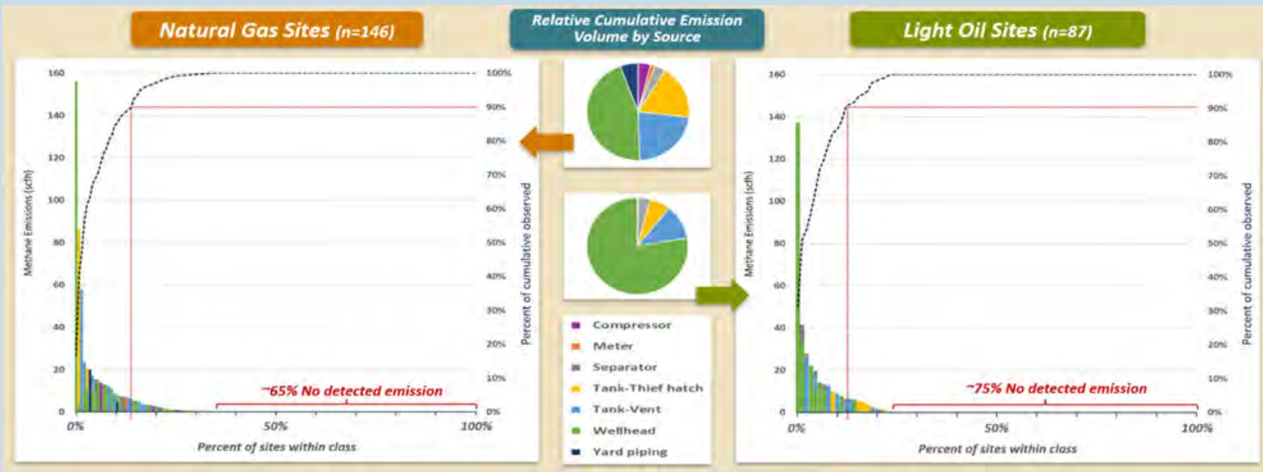

Figure 2. Site-wide methane emissions

■ **Emissions Screening and Measurements.** Gas emissions were detected using an *optical gas imaging* camera and quantified, where possible, using a *high flow sampler* in conjunction with gas composition-specific analyses. One emission was measured using the *downwind tracer flux method.*

■ **Frequency of Detected Emissions.** Table 1 summarizes the frequency of detected emissions, which varied widely and exhibited *no discernable pattern relative to observed equipment types or type of production*. On a site-wide basis, no emissions were detected at ~ 65% of natural gas sites and ~75% of oil sites (see Figure 2). Approximately 90% of the cumulative detected emissions detected are attributable to ~12% of the visited sites for both types of production.

■ **Magnitude of Detected Emissions.** The emission rate measurements exhibit the long-tail behavior commonly observed in air emissions studies. Approximately 90% of observed emissions were less than 13 standard cubic feet per hour (scfh).

Table 1. Summary of observed equipment and detected emissions

	Natural Gas Sites (n 146)			Light Oil Sites (n=87)		
Equipment Category	#Equipment Observed	#Emissions Detected	Emission frequency	#Equipment Observed	#Emissions Detected	Emission frequency
Wellheads	165	32	19%	97	13	13%
Meters	157	3	2%	7	2	29%
Compressors	4	3	75%	2	0	0%
Separators	130	4	3%	28	4	14%
Dehydrators	1	0	0%	0	0	-
Tanks	157	-	-	68	-	-
Thief hatches	-	4	3%	-	8	12%
Vents	-	16	10%	-	14	21%

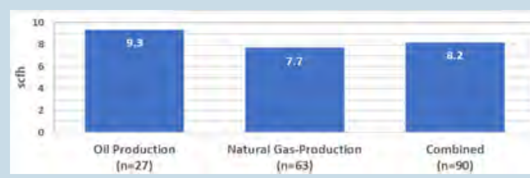

Figure 3. Average detected methane emission rates

The top 10% of emission sources contributed 72% of the total measured emissions, and the top two emission sources alone accounted for 40%. Figure 3 summarizes the overall average measured methane emission rates.

PENDING COMPREHENSIVE DATA EVALUATION

Once qualified datasets from all regional field campaigns are fully developed, comprehensive exploratory and statistical data analyses will be performed to identify *key groupings of sites in the studied regions and their distinguishing characteristics and emission profiles* (see Figure 4). Data analyses are ongoing; therefore, the limited analysis and representations of data shown here, and any interpretation of the same, should be considered preliminary. It is important to recognize that the results presented here represent only a small fraction of the diversity of marginal well site characteristics present around the country (see Figure 1). Further investigation of sites exhibiting a broader range of product types, production rates, and site equipment counts in the remaining two field campaigns will provide more representative results and more meaningful conclusions upon completion of this project.

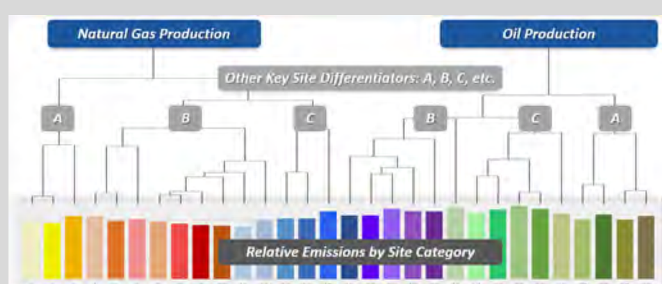

Figure 4. Conceptual example of data analysis
Besides product type, other key differentiators may include "size" (equipment count), production rate, or other factors.

A Technical Advisory Steering Committee (TASC), consisting of stakeholders from industry, academia, regulatory agencies, and non governmental organizations, provides recommendations and feedback on project activities, such as strategy development, field implementation, data analysis, and study conclusions, throughout the project.

While Catalyst Energy generally supports reduction of VOC and methane emissions, I feel it is important to make some comments to the EPA regarding the conventional industry in the Appalachian Basin. As someone with over 40 years' experience in most aspect of upstream and midstream operations I wanted to address differences in conventional oil and gas well drilling and operations from other basins and from unconventional operations.

The Agency has an imperfect idea as to the distinction between conventional and unconventional operations. Various legal definitions further cloud the issue. Pennsylvania's own definition differs from federal definitions. The Pennsylvania definition is based in lithology. The Agency wrongly confuses the issue by referring to conventional wells as 'not hydraulically fractured'. Conventional wells in Pennsylvania and much of the Appalachian Basin have largely been fracked since the 1960's and since the 1970's nearly all conventional wells have been fracked. The difference from unconventional operations is scope.

A conventional oil well will have a very small footprint during drilling and frack operations. A typical location will only be perhaps 5000 square feet while an unconventional horizontal well will clear over 200,000 square feet. When reclaimed after frack operations a typical well, oil or gas, will only leave enough of a clearing for the well, a pumping unit if it is an oil well or a brine tank if it is a gas well and enough room to pull a service rig in to work on the well in the future.

Where an unconventional well frack job will pump millions of gallons of water and chemicals a conventional frack job usually involved 100,000 to 200,000 gallons of water with little or no chemicals. Much of the water used is production water and much is recycled during the job. In addition, a conventional frack is usually done in one day, sometimes 2. Little flowback occurs during these jobs and nearly no natural gas is released. The well is typically placed on production almost immediately with no cleanup or flowback.

Regulating these jobs with an eye toward methane reduction would result in very little reduction of methane release while driving the cost to something untenable for recovery equipment.

I believe the EPA should exempt conventional frack jobs from this type of regulation due to the lack of any cost benefit from reduction and due to the adverse impact it will have on future development and employment.

There have been almost no conventional vertical gas wells drilled in Pennsylvania in the last 10 years. The legacy gas wells produce at low pressures and at low rates. Drilling of conventional oil wells has declined over 90% in the same time period. New oil wells are often stripper wells from the onset and almost always stripper wells within a few months. Most legacy wells produce oil in quantities of a few gallons per day, perhaps ¼ barrel. Well head pressures are kept as low as possible to maintain whatever

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flow of oil there is. The potential for meaningful leakage of methane and VOCs is so low that any regulation and reporting will consume valuable resources and time to little avail. I request that these legacy and stripper wells be exempt from that burden. Too many jobs will be lost and wells abandoned when they could still be produced economically.

Much the same arguments apply to conventional well oil tanks. Most producers employ centralized tank batteries to conserve money. These batteries may service 20, 30, 40 or more wells. Most have separators to conserve and produce what little gas there is. Since there is commonly very little pressure on the wells very little gas is evolved from the oil in those tanks. A pressurized hatch holding a few ounces pressure on the tank (if the tank design allows for that type of hatch) should be sufficient since off gassing under any circumstance is very low on older wells. Addition of monitoring for volumes or recovery of vapors is beyond the means of most operations and would be of minimal effectiveness. Comments by the Pennsylvania Grade Crude Oil Coalition, to which I serve as vice president, will back that up.

The EPA has made it known that liquid unloading is being considered for regulation. Technology or equipment to facilitate that should be considered carefully before such a decision is made. The Agency must familiarize itself with various techniques and understand the impacts of changes. Liquids unloading takes many forms. From simply blowing a gas well down to a tank to bailing an open hole to swabbing a cased hole to various types of artificial lift. Artificial lift may be plunger lift, casing swabs or pumping a well. All these techniques except bailing or pumping depend on velocity up the casing or tubing to lift liquids effectively. That means blowing to a tank in most cases and anything that impedes the velocity in order to recover gas would reduce effectiveness and result in increased frequency of the unloading operation. Techniques or technology will have to be developed in order to do this in such a way as to preserve the effectiveness while reducing methane emissions, and I am not aware of any in existence as of now.

I would like to thank the Agency for reaching out to industry and allowing me to serve as an SER.

Douglas E. Jones

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August 12, 2021

Submitted via email

Lanelle Wiggins
RFA/SBREFA Team Leader
US EPA - Office of Policy
1200 Penn Ave NW
Washington DC, 20460

Re: SBAR Panel Review of the Oil and Natural Gas Sector New Source Performance Standards Rule

Dear Ms. Wiggins:

Western Energy Alliance submits the following comments on the Environmental Protection Agency's (EPA) upcoming Oil and Natural Gas Sector New Source Performance Standards (NSPS) rulemaking as part of the Small Business Advocacy Review (SBAR) panel process. We strongly support the goal of the Small Business Regulatory Enforcement Fairness Act (SBREFA) to avoid and reduce significant impacts on small entities such as the numerous oil and natural gas companies that will be subject to the new NSPS rule, and we appreciate the opportunity to engage with EPA prior to the release of a draft regulation.

Western Energy Alliance represents 200 companies engaged in all aspects of environmentally responsible exploration and production of oil and natural gas across the West. The Alliance represents independents, the majority of which are small businesses with an average of fourteen employees.

The Alliance intends to fully engage in the formal rulemaking process once a draft rule is proposed, but we also believe compliance with SBREFA as part of this effort is a vital and appropriate initial step. Unfortunately, as a result of an arbitrary deadline established under the Executive Order (EO) on "Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis," engagement with the SBAR panel has been limited and rushed. We acknowledge that EPA staff have made a good-faith effort to engage with the panel while simultaneously working to meet the September 2021 deadline in the EO, but wish to express our overall concern that the process has been given short shrift.

The comments below respond to the two presentations given to the SBAR panel and highlight important considerations for EPA as the agency moves through the regulatory process. We especially urge EPA to consider the potential cost and regulatory impacts to small oil and natural gas companies as the final rule is developed.

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Regulatory Certainty and Consistency

The Congressional Review Act (CRA) resolution overturning the 2020 OOOOa Policy Rule has created confusion regarding what aspects of the previous OOOOa rule from 2016 are in place and what aspects of the 2020 OOOOa Technical Rule have superseded previous provisions. EPA should prioritize alignment of the 2016 requirements with the 2020 Technical Rule by clearly adopting the changes in the upcoming rulemaking.

As indicated on Slide 4 of the presentation to the SBAR panel, EPA "successfully" implemented changes in the 2020 Technical Rule to reduce the burden from recordkeeping and reporting requirements, and finalized the Compliance and Emissions Data Reporting Interface (CEDRI) template in April 2021. We agree that these changes have been successful and urge EPA not to abandon them in a new rule.

The development of the CEDRI template was a success for EPA as well, and the benefits of using the electronic reporting template and streamlining associated with the technical rule would be lost should the changes not be brought forward into the new rule. Furthermore, Alliance members and other members of the small business community have already adjusted their processes and compliance strategies to comply with the 2020 Technical Rule, expecting that the rule would not be impacted by a repeal of the 2020 Policy Rule. To avoid unnecessarily burdening small businesses, imposing significant costs on the regulated public with very little benefit, and creating regulatory uncertainty, EPA should implement the 2020 Technical Rule changes in the new rule.

Fugitive Emissions

Fugitive emissions as a category has required a creative approach from EPA throughout the development of OOOOa, and EPA has attempted to keep up with modern trends and technological advancement in the methane detection technology. That said, the world of methane detection and understanding of emissions has changed immensely over the last few years. As new technologies around aircraft, drone and potentially satellite-based emissions detection technologies emerge, and as those techniques are compared to continuous sitewide emissions monitoring and traditional infrared camera-based leak detection and repair (LDAR) programs, companies are learning a lot more about typical emissions profiles from facilities and their sources.

EPA suggested in the SBAR panel presentation that monitoring frequency could be determined by site-based emissions. The Alliance supports the use of aerial, satellite and other forms of monitoring for fugitive emissions beyond traditional LDAR, but only as an alternative and not as an additional requirement.

In the past few years, aerial methane detection services have become more widely available, with numerous studies being done across multiple oil and gas basins in the United States. The technology includes both satellite methane detection with the ability to detect emissions on a facility-wide basis, as well as airborne high-resolution methane monitoring with the ability to detect emissions down to the component level in some cases. This technology can be quite costly with a wide range of factors impacting the potential cost to operators including the range of the operations, pipeline right-of-way mileage, mobilization fees for aircraft, and even terrain impacts in areas such as the Piceance Basin.

Furthermore, fixed-wing flyovers often require follow up with a ground-based infrared camera in order to ground truth any emission sources identified as leaks or abnormal emissions. Aerial surveys can often point to emission sources at facilities, but ground-based crews often must verify if the source is a persistent or a transitory, short-lived event.

On the cost side, some aerial survey vendors charge on a per facility basis while others would have a fee based on the size of the actual basin. Companies have seen costs ranging from $50,000 to $240,000 to complete a single fixed-wing methane survey of a primary asset area (typically including all facilities in a given basin). Other cost estimates to cover an entire field have been estimated to be in the $125,000 range for approximately 1000 square miles. On a per-facility basis, these costs would range from between $110 and $176 for an individual facility based on the frequency of aerial surveys that a company commits to for a given year.

There has also been discussion around multi-client campaigns where companies would share in mobilization costs, which would be more efficient in fields where multiple operators are in the same basin. This would likely be critical for smaller operators as funding an individual-operator aerial survey would be quite costly and inefficient.

To encourage adoption of those new technologies, EPA should provide relief from LDAR monitoring frequency in exchange for demonstrations that site-wide emissions are lower than a certain threshold. This could serve multiple purposes. First, it would encourage the adoption of new technology, driving more innovation and providing an incentive to further our understanding of emissions generally. Second, it could potentially cut down on emissions associated with traveling to facilities on increased monitoring frequencies, especially for those facilities that could otherwise be demonstrated to be low emitting.

Finally, as many of the technologies for demonstrating field-wide or site-wide emissions are larger in scale and often cover broad areas, the adoption of these new broad-ranging technologies could make it easier for small operators and businesses to participate in those programs, as the cost of those programs could be borne by all operators in a certain area, as opposed to the costs being distributed individually. We therefore urge EPA to consider allowing a reduced frequency of monitoring for facilities that have demonstrated lower emissions through aerial monitoring.

Storage Vessels

Within the storage vessel portion of the SBAR presentation, EPA mentions a few concepts and ideas that could potentially impact small operators. First, the language suggests potentially basing applicability for storage tanks on methane emissions instead of VOCs. This may seem like a rather straightforward change, but it could have particularly burdensome consequences for operators in their data management, recordkeeping, and monitoring programs.

The original OOOO came into effect for facilities brought online from 2011 afterward. Changing applicability determinations, threshold, and classifications of facilities a decade later should be carefully considered. Also, there would likely be very little meaningful benefit for changing applicability based on methane. VOCs have been specifically identified by EPA as a closely correlative proxy for methane emissions in oil and natural gas production, and as such, any change in applicability would likely only impact a very small percentage of facilities. However, the change in threshold would require operators to go back and put extensive effort into developing new applicability determinations for their facilities, resulting in significant cost and waste, with virtually no environmental benefit. EPA should maintain the current applicability based on VOCs.

Similarly, EPA mentioned in the SBAR presentation the idea of providing applicability to entire tank batteries instead of individual tanks. Perhaps when the original OOOO was being conceived, a tank battery as an affected facility could have been a better option. In fact, EPA received comment from industry and environmental organizations at the time expressing opinions applicable to both types of applicability at the time. However, now that the rule has been in effect for a long period of time, it would be most prudent to keep the current tank applicability threshold in place. We also support the 2020 Technical Rule's clarification that averaging emissions across a controlled tank battery can be used to determine applicability.

EPA could, however, accomplish the same goal by providing an off ramp or an alternative applicability option for tanks that are part of a larger battery. In this situation, EPA could set a threshold at 24 tpy of VOC (for a typical facility with 4 oil tanks, each at the 6 tpy threshold) for tank batteries and allow those facilities to be not affected facilities or set a slightly lower threshold as an off ramp for low producing facilities. This could avoid the sometimes-tedious task of specifically calculating or assigning emissions to individual tanks without changing the current applicability threshold.

Finally, EPA received comments from the small entity representatives that there are situations that exist where propane and other fuel sources are being maintained on sites and burned continuously as pilot flames for control devices for storage tanks in situations where the associated wells do not continue to produce enough gas to power the combustion devices. This situation arises both as a result of OOOOa and various state rules, and is oftentimes wasteful, as it has the potential to result in more emissions from the burning of the fuel than would be controlled from the tanks. To avoid this problem, EPA should enhance the offramp provision for storage tanks whose emissions cross below a certain threshold.

Compressors

Within the presentation's discussion of compressors, EPA introduces the concept of a centralized production facility for determining applicability of certain requirements. EPA also provides a potential definition from Colorado. The definition provided in the materials includes "all equipment at a single stationary source directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. This equipment includes, but is not limited to, equipment used for storage, separation, treating, dehydration, artificial lift, combustion, **compression**, pumping, metering, monitoring, and flowline." [emphasis added].

Under this definition, a site that only had a single wellhead and a compressor would be considered a centralized production facility. As a result, this definition is essentially meaningless, as it would apply to functionally all production facilities. The Alliance encourages EPA to not adopt a definition for centralized production facilities, but to instead focus on emission reductions from equipment as currently delineated by NSPS OOOOa.

Liquids Unloading

If EPA decides to include new requirements for liquids unloading in the upcoming rule, the agency should employ a series of best management practices that align with those used by members of the Environmental Partnership, according to their protocol. By the end of 2020, the Environmental Partnership had 83 companies participating in their programs, operating in basins across North America and the world. In the same year, those companies minimized emissions from more than 44,000 liquids unloading events. The methodology used in the Environmental Partnership is proven to be achievable, effective, and relatively inexpensive compared to other potential emission reduction techniques.

The best management practice approach from the Environmental Partnership is functionally very similar to the OOOOa requirements for hydraulically fractured wells using Reduced Emission Completion equipment. Essentially, like the way that flowback should be done until there is sufficient gas present to allow separation and routing to sales, liquids unloading, if manually monitored, can be performed similarly. Once liquids are unloaded and gas can be routed to sales, the well should be turned to sales again. Under the Environmental Partnership's protocol, participants commit to monitoring the manual unloading process on-site or in close proximity and close all wellhead vents to the atmosphere as soon as practicable. This minimizes emissions from the event and doesn't require the installation or use of specialized equipment.

Conclusion

Western Energy Alliance appreciates the opportunity to engage in the SBAR process as part of EPA's compliance with the Small Business Regulatory Enforcement Fairness Act. Our small, independent member companies will be especially impacted by the changes contemplated in the presentations provided to the review panel, so we urge EPA to consider the above comments as it is developing the draft rule. Please do not hesitate to contact me for further information.

Sincerely,

Tripp Parks
Vice President of Government Affairs