

December 8, 2017

The Honorable Scott Pruitt, Administrator  
US Environmental Protection Agency  
1200 Pennsylvania Avenue, N.W.  
Washington, DC 20460

**VIA E-MAIL AND E-FILING**

**Re: Environmental Protection Agency's Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources: Stay of Certain Requirements at 82 Federal Register 51788 (November 8, 2017)**

**Docket ID No. EPA-HQ-OAR-2010-0505**

Dear Administrator Pruitt:

The following comments are submitted on the above-referenced proposed rule and notice of data availability ("NODA") on behalf of the following national and state trade associations: the Independent Petroleum Association of America ("IPAA"), American Exploration & Production Council ("AXPC"), Domestic Energy Producers Alliance ("DEPA"), Eastern Kansas Oil & Gas Association ("EKOGA"), Illinois Oil & Gas Association ("IOGA"), Independent Oil and Gas Association of West Virginia, Inc. ("IOGA-WV"), Indiana Oil and Gas Association ("INOGA"), International Association of Drilling Contractors ("IADC"), Kansas Independent Oil & Gas Association ("KIOGA"), Kentucky Oil & Gas Association ("KOGA"), Michigan Oil and Gas Association ("MOGA"), National Stripper Well Association ("NSWA"), North Dakota Petroleum Council ("NDPC"), Ohio Oil and Gas Association ("OOGA"), Oklahoma Independent Petroleum Association ("OIPA"), Pennsylvania Independent Oil & Gas Association ("PIOGA"), Texas Alliance of Energy Producers ("Texas Alliance"), Texas Independent Products & Royalty Owners Association ("TIPRO"), and West Virginia Oil and Natural Gas Association ("WVONGA") (collectively, "Independent Producers"). The Independent Producers have participated individually or through IPAA in most, if not all, of the rulemakings and associated litigation since the Environmental Protection Agency ("EPA" or "Agency") proposed to revise the New Source Performance Standards ("NSPS") for the Oil and Natural Gas Sector in August 2011. 76 Fed. Reg. 52,738 (Aug. 23, 2011). While most of the Independent Producers represent companies that engage in large volume hydraulic fracturing horizontal or unconventional drilling, a significant portion of their membership is also comprised of "mom and pop" operations that engage in some form of hydraulic fracturing as defined by EPA, generally involving vertical wells drilled into

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geological formations currently referred to as conventional wells. From the beginning of these rulemakings, most of the Independent Producers have tried to illustrate to the EPA that their “one-size-fits-all” approach to regulating this industry is inappropriate. The NODA represents another, necessary, opportunity to work with the EPA to tailor 40 C.F.R. Part 60, Subpart OOOOa (“Subpart OOOOa”) to reduce the impact on the Independent Producers and their individual members while still providing adequate protection of the environment. The Independent Producers’ Petition for Reconsideration submitted on August 2, 2016, to the EPA outlines the primary issues that should be addressed during the two-year time period set forth in the NODA.<sup>1</sup> As a result of various factors, including the regulatory burden, many individual members of the Independent Producers have not drilled a single well in the past five years. The two-year extension of compliance deadlines set forth in the NODA will have a tremendous benefit to the Independent Producers and their individual members, while having little to no negative impact on the environment. The proposed two-year time period is entirely appropriate for the Independent Producers to educate the new Administration on their concerns, as well as make the appropriate and necessary changes to current regulations. The following comments are generally organized according to the questions and topics set forth in the NODA. These comments include remarks from certain members of the Independent Producers who request anonymity while others are not concerned with being recognized. To the extent the EPA would like additional information regarding a particular comment, please contact me and I will serve as an intermediary to provide additional information.

## **GENERAL COMMENTS**

### **A. Legal Basis for EPA Revision of Original Proposal**

The Independent Producers concur that the EPA has adequate authority to pursue either a stay of an extension of implementation pursuant to the Agency’s authority under both Clean Air Act (“CAA”) Section 111 as well as the Federal Administrative Procedures Act (“APA”) Section 705. Moreover, the EPA need only establish that the reasons for the new policy are sound.

[T]he agency must show that there are good reasons for the new policy. But it need not demonstrate to a court’s satisfaction that the reasons for the new policy are better than the reasons for the old one; it suffices that the new policy is permissible under the statute, that there are good reasons for it, and that the agency believes it to be better, which the conscious change of course adequately indicates.

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<sup>1</sup> A copy of the Independent Producers’ August 2, 2016 Petition for Reconsideration is attached for inclusion in the administrative record.

*FCC v. Fox Television Stations, Inc.*, 556 U.S. 502, 515 (2009) (emphasis omitted).

In anticipation of commentary from environmental groups who will presumably object to a stay or extension, the Independent Producers remind the EPA of the holding in the *National Association of Home Builders* case in 2012. “The fact that the original [rule] was consistent with congressional intent is irrelevant as long as the amended rule is also ‘permissible under the statute.’” *Nat’l Ass’n of Home Builders, et al., v. EPA*, 682 F.3d 1032, 1037 (citing *Fox*, 556 U.S. at 515). The petitioners acknowledge that, although they believe the original rule was better, the amended rule is permissible. Oral Arg. Recording at 17:40-:43. As *Fox* made clear, that “suffices” as far as the court is concerned. *Fox*, 556 U.S. at 515. As *Fox* noted, the Supreme Court has “neither held nor implied that every agency action representing a policy change must be justified by reasons more substantial than those required to adopt a policy in first instance.” *Fox*, 556 U.S. at 514 (citing *Motor Vehicle Manufacturers Ass’n of the United States, Inc., et al., v. State Farm Mutual Automobile Insurance Co., et al.*, 463 U.S. 29, 42 (1983)). To the contrary, the *State Farm* case affirmed that “[a]n agency’s view of what is in the public interest may change, either with or without a change in circumstances.” *State Farm*, 463 U.S. at 57 (quoting *Greater Boston Television Corp. v. FCC*, 444 F.2d 841, 852 (D.C.Cir.1970)); see *Am. Trucking Ass’ns v. Atchison, Topeka & Santa Fe Ry. Co., et al.*, 387 U.S. 397, 416 (1967) (declaring that an agency, “in light of reconsideration of the relevant facts and its mandate, may alter its past interpretation and overturn past administrative rulings”). *Nat’l Ass’n of Home Builders*, 682 F.3d at 1037.

The Independent Producers generally feel that an extension, as opposed to a stay, is a more appropriate approach and more in keeping with the agency’s discretionary authority under the two applicable statutes.

## **B. Reinstate Low Production Well Exemption**

Perhaps the single most important issue to many of the Independent Producers is the need to reinstate the low production well exemption from the fugitive emissions requirements (Leak Detection and Repair (“LDAR”)) and extend the compliance deadline for two years while the exemption is reevaluated. The following comment was received from a small independent operator in Texas and is representative of many smaller companies across the country:

I am a small operator of marginal oil wells and have been operating at a negative cash flow the last few years. My production facility has back pressure vent valves and I have passed recent Railroad Commission field inspections. My lease produces less than 15 barrels of oils per day or equivalent (“BOE”) and adding an additional regulatory expense burden will force me to discontinue operations and plug and abandon the existing marginal wells.

It is that simple. The LDAR requirements on low production wells represents the death knell to many wells and has little environmental benefit. Application of the fugitive emissions program on low producing wells and on refractured existing wells should be delayed until the EPA can reconsider its position on these facilities

When the EPA proposed Subpart OOOOa, it excluded the application of its fugitive emissions requirements for low producing wells – oil wells producing 15 BOE or less and natural gas wells producing 90 mcf or less. In finalizing Subpart OOOOa, the EPA withdrew the low producing well exclusion. It based this decision on a specious analysis of methane emissions by the Environmental Defense Fund (“EDF”). The Independent Producers petitioned the EPA to reconsider its action. The EPA granted portions of the Independent Producers’ Petition for Reconsideration, including the removal of the low production well exemption on April 18, 2016. For the reasons set forth below, the EPA should, at a minimum extend the compliance deadlines for low production wells complying with the LDAR provisions as well as the reduced emission completions requirements as they apply to low production wells.

The impact of the fugitive emissions program falls more heavily on low producing wells than larger producing wells. Moreover, unlike other provisions of Subpart OOOOa, the fugitive emissions requirements are perpetual operating costs rather than initial capital costs. The EPA’s regulatory analysis made no determination that addressed the differences in the cost effectiveness of its fugitive emissions program on low producing wells. Compounding this failure, the EPA’s use of an inappropriate definition of modification in Subpart OOOOa is suppressing normal processes to extend the life of oil and natural gas production operations because these actions would trigger application of the fugitive emissions requirements.

Moreover, as the Independent Producers explained in their Petition for Reconsideration, the EPA’s logic and reasoning in Subpart OOOOa is internally inconsistent. The EPA assumes that replacing equipment that increases production will increase emissions because of pressure and production. Yet, the EPA ignored that reality when it came to low production wells and indicated pressure and production did not play a role in emissions – and instead claimed that it was a function of the number of components and connections. That is manifestly unfair and the provisions need to be stayed or the compliance deadline needs to be extended until the EPA cannot only explain their inconstant logic, but also better understand the quantity of emissions from leaks at low production wells and the costs associated with the LDAR requirements, especially as they apply to small entities. The EPA previously recognized the legitimacy of this concern and granted an opportunity for notice and comment in the Administrator’s letter to the Independent Producers, *et al.*, dated April 18, 2017. The following is a detailed explanation supporting this request.

When EPA finalized Subpart OOOOa, the rule included the following assertions:

Several commenters stated that the EPA should not exempt low production well sites because they are still a part of the cumulative emissions that would impact the environment. *One commenter indicated that low production well sites have the potential to emit high fugitive emissions.* (Emphasis added) Another commenter stated that low production well sites should be required to perform fugitive emissions monitoring at a quarterly or monthly frequency. One commenter provided an estimate of low producing gas and oil wells that indicated that a significant number of wells would be excluded from fugitive emissions monitoring.

Based on the data from DrillingInfo, 30 percent of natural gas wells are low production wells, and 43 percent of all oil wells are low production wells. The EPA believes that low production well sites have the same type of equipment (*e.g.*, separators, storage vessels) and components (*e.g.*, valves, flanges) as production well sites with production greater than 15 boe per day. Because we did not receive additional data on equipment or component counts for low production wells, we believe that a low production well model plant would have the same equipment and component counts as a non-low production well site. This would indicate that the emissions from low production well sites could be similar to that of non-low production well sites.

We also believe that this type of well may be developed for leasing purposes but is typically unmanned and not visited as often as other well sites that would allow fugitive emissions to go undetected. We did not receive data showing that low production well sites have lower GHG (principally as methane) or VOC emissions other than non-low production well sites. In fact, the data that were provided indicated that the potential emissions from these well sites could be as significant as the emissions from non-low production well sites because the type of equipment and the well pressures are more than likely the same. In discussions with us, stakeholders indicated that well site fugitive emissions are not correlated with levels of production, but rather based on the number of pieces of equipment and components. Therefore, we believe that the fugitive emissions from low production and non-low production well sites are comparable.

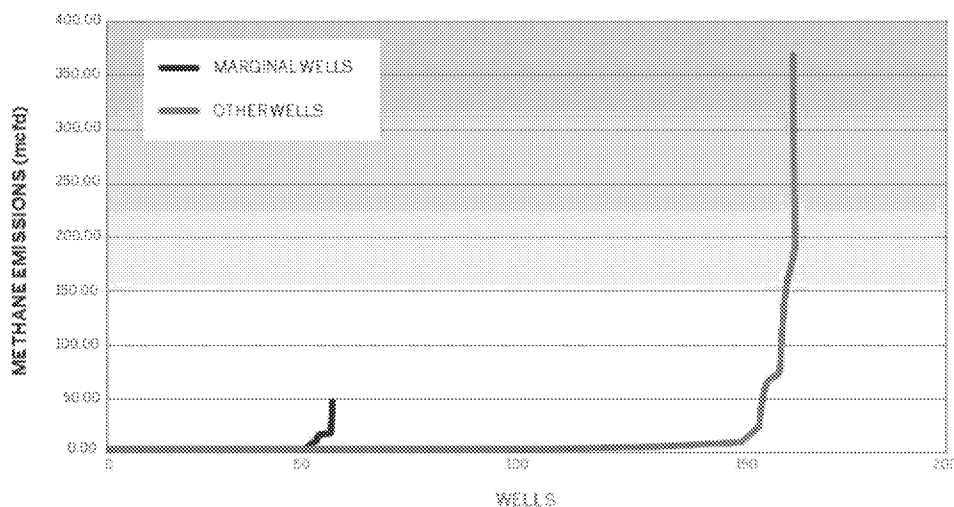
Based on these considerations and, in particular, the large number of low production wells and the similarities between well sites with production greater than 15 boe per day and low production well sites in terms of the components that could leak and the associated emissions, we are not exempting low production well sites from the fugitive emissions monitoring program. Therefore, the collection of

fugitive emissions components at all new, modified or reconstructed well sites is an affected facility and must meet the requirements of the fugitive emissions monitoring program.

*Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources*, 81 Fed. Reg. 35824, 35856 (June 3, 2016). The italicized sentence above refers to an EDF study designed to create the illusion that low producing wells were really “super-emitters.” This study was then characterized as the basis for removing the low producing well exclusion for the Subpart OOOOa fugitive emissions program. Contrary to this study, a recent Department of Energy-funded, peer-reviewed study conducted by researchers from Pennsylvania State University found that methane leakage rates from natural gas wells and other infrastructure in the Northeast Marcellus Shale are roughly 0.4% of production. This leakage rate is well below the threshold for natural gas to maintain its climate benefits over other traditional fuel alternatives. This study may be publicly accessed at the following internet link <https://www.atmos-chem-phys.net/17/13941/2017/acp-17-13941-2017.pdf>. This new information contradicts the EDF study and is sufficient basis for the EPA to stay the compliance deadline for LDAR requirements as they pertain to low production wells.

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

Before turning further to describe the submitted study, it is useful to look at the same data using a direct graph of emissions.



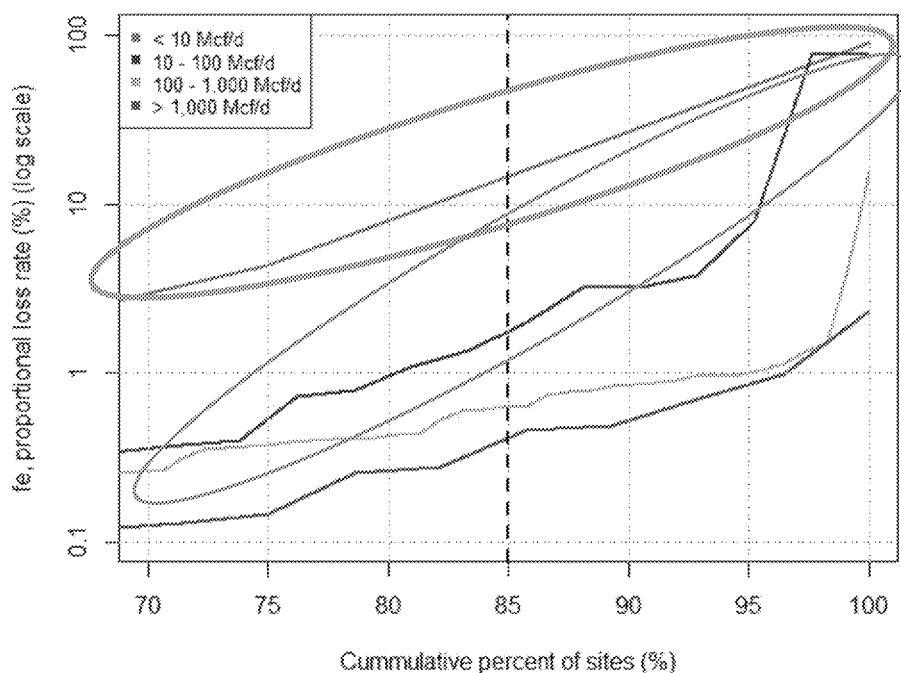
In this graph, marginal wells are those with production volumes of 90 mcf/d or less.

Graphing the data this way is consistent with information from other studies showing that a small portion of wells have an emission profile for some reason with high emissions and most wells have really low emissions. Importantly, it also clearly shows that marginal wells – low producing wells in the context of the regulation – have far smaller emissions. But, since this graph is using the same data as the study, it could also be overstating emissions because of scaling short term emissions to a daily amount.<sup>2</sup>

With this background, turning to the presentation of the same material in the study demonstrates how it was manipulated.

Below is the graphic used to present the data. It would suggest that the worst emitting operations – the “super-emitters” – are the smallest wells (the orange line and the blue line, circled in green). Having directly plotted this data, the obvious issue is how such a result can occur.

<sup>2</sup> For example, a recent National Oceanic & Atmospheric Administration study, *Improved Mechanistic Understanding of Natural Gas Methane Emissions from Spatially Resolved Aircraft Measurements*, raised issues regarding the time of day when data is collected because of normal operational and maintenance activities that occur during morning and midday hours.



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

First, it shows emissions as a percentage of production rather than actual emissions. Thus, 1 mcf emitted out of 10 mcf produced is 10%, but 50 mcf emitted out of 1000 mcf produced is 5%. As a result, it skews the perception of the data to imply that low producing wells are large emitters when they are not.

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

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

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

These observations can be made without conducting an intense investigation of the study. They are obviously intended to contort data to create a specific result. Yet, with all the investigative power at the EPA, with all of the research the EPA has conducted, the EPA took this contrived

study at face value to make its determination to remove the low producing well exclusion in the Subpart OOOOa regulations.

In addition to this mischaracterization of the emissions nature of low producing wells, the EPA never did a cost effectiveness analysis of the fugitive emissions program as it applies to these facilities. Not surprisingly, the impact is significantly different between small and large wells. For the past several years, the EDF has scammed the country and many regulators with an analysis that it developed showing that a variety of methane controls are cost effective. The EDF likes to state that these controls only cost a few cents.

The problem is that the EDF's analysis is flawed and, when the average low producing well produces 22 mcf per day, a few cents per mcf means a lot. The EDF initially contracted with the ICF International ("ICF") to develop its economic analysis of methane emissions controls. In 2016, ONE Future Inc., contracted with the ICF to revisit its prior work using more realistic assumptions.<sup>3</sup> One key assumption – an assumption that is also problematic with the EPA's economic analysis for Subparts OOOO and OOOOa – is the value of methane used in the analyses. The EDF and the EPA use a value of \$4.00/mcf. This is not a realistic value. The ONE Future analysis used \$3.00/mcf, which is close to the current national wellhead price for natural gas but still conservative (low). Equally important, it reflected that a producer does not receive this amount due to royalties and fees that are about 25% of the wellhead price and therefore reduces the net to the producer to about \$2.25/mcf. However, even the ONE Future/ICF report does not attempt to distinguish the cost effectiveness of controls based on size of operation.

However, it can be done. The ONE Future/ICF study developed information on the cost of a fugitive emissions leak detection and repair (LDAR that approximates the Subpart OOOOa biannual testing program. It concluded that the annual cost for the program is \$3,436.<sup>4</sup>

There are little data on the emissions from low producing wells. However, in the EPA's April 2012 Technical Support Document for its NSPS,<sup>5</sup> it created a model plant well pad for one well that estimates methane emissions at 0.330 tons/year.<sup>6</sup> This translates to 16 mcf/year.

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<sup>3</sup> *Economic Analysis of Methane Emission Reduction Potential from Natural Gas Systems*, ICF International, May 2016.

<sup>4</sup> As noted and set forth in their own cost analyses below, the Independent Producers submit that this agency estimate is low.

<sup>5</sup> *Oil and Natural Gas Sector: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution. Background Supplemental Technical Support Document for the Final New Source Performance Standards*, EPA, April 2012.

<sup>6</sup> *Ibid*, Appendix C.

The ICF analysis uses an estimate that 50% of these emissions would be reduced by the LDAR program. Using the more realistic product prices, this recovery adds about \$17.50 to the income of the well and reduces the net cost to about \$3,418/year. It is noteworthy to point out that even this small recovery may overstate the amount. Field experience with state fugitive emissions programs indicates that after the first examination of a facility and the initiation of operation and maintenance programs on equipment, subsequent LDAR reviews find far fewer leaks to repair.

The larger question is what impact does this have on a low producing well. Using the ICF assumptions, the average low producing well (22 mcf per day) would receive daily income of \$49.50 (\$18,000 per year).

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

Consequently, the average low producing well would have to manage its finances in a range from a daily income of \$4.18 to a loss of \$58.95. In this difficult financial situation, the application of the EPA LDAR program is a more significant factor than EPA has presumed in its analysis. The daily cost of its program would be \$9.36 – after taking into account methane recovery. For a low producing well, this small change would drive the well into a net loss ranging from about \$5.00/day to \$68.00/day.

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

Additionally, in the context of the EPA’s immediate need to consider staying the fugitive emissions requirements, the impact of the Subpart OOOOa NSPS on modifications is significant. The CAA defines “modification” in the context of Section 111 as:

...any physical change in, or change in the method of operation of, a stationary source which increases the amount of any air pollutant emitted by such source or which results in the emission of any air pollutant not previously emitted.

42 U.S.C.A. § 7411(a)(4) This is not the criteria that the EPA used in defining “modification” in Subpart OOOOa. In Subpart OOOOa, the EPA states:

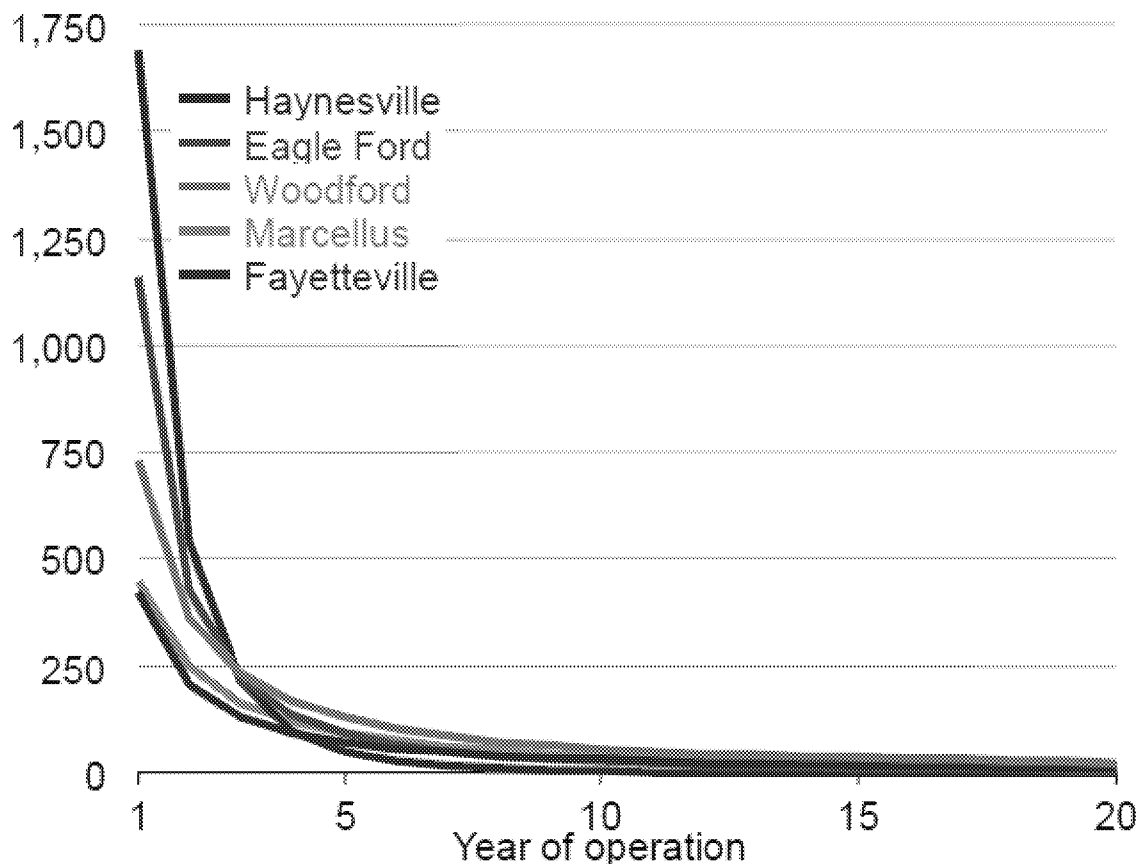
A “modification” to a well site occurs when:

- (i) A new well is drilled at an existing well site;
- (ii) A well at an existing well site is hydraulically fractured; or
- (iii) A well at an existing well site is hydraulically refractured.

81 Fed. Reg. 35900 (June 3, 2016). The EPA justifies its use of this definition in the Federal Register Notice on Subpart OOOOa by stating:

The EPA believes the addition of a new well or the hydraulically fracturing or refracturing of an existing well will increase emissions from the well site for the following reasons. These events are followed by production from these wells which generate additional emissions at the well sites. Some of these additional emissions will pass through leaking fugitive emission components at the well sites (in addition to the emissions already leaking from those components). Further, it is not uncommon that an increase in production would require additional equipment and, therefore, additional fugitive emission components at the well sites. We also believe that defining “modification” to include these two events, rather than requiring complex case-by-case analysis to determine whether there is emission increase in each event, will ease implementation burden for owners and operators. For the reasons stated above, EPA is finalizing the definition of “modification” of a well site, as proposed.

81 Fed. Reg. 35881 (June 3, 2016). This rationale is generally incorrect because emissions do not arise from the fracturing of a well but from production and the equipment to manage these emissions would be in place at the time of the fracturing. But, it is specifically incorrect with regard to the refracturing of wells. Refracturing of a well is a normal operational practice to sustain production from existing wells. The EPA has never seemed to grasp the concept that oil and natural gas wells decline over time. The following graph shows a typical decline curve for hydraulically fractured wells.



As a well produces, its rate declines over time. The equipment that manages air emissions at a facility must be designed for its initial production. A normal practice to extend the life of a well is a workover or secondary recovery project that recovers some portion of the well's production. For hydraulically fractured wells, refracturing is a method that allows additional production from the well. Importantly, refracturing will not bring the well production back to its initial volume or pressure. Therefore, refracturing will not increase emissions at the well site because the emissions management facilities will operate below their initial design volumes.

In using the Subpart OOOOa modification definition, the EPA violates the direct definition of modification in Section 111 of the CAA. And, it is creating consequences.

Because the fugitive emissions requirements are a perpetual cost that attaches to each well that becomes subject to Subpart OOOOa, declining wells that need to be refractured to maintain their production are not being addressed. As a result, American oil and natural gas that could be produced, will not be produced. The loss of this production should concern the EPA and it should act to forestall these adverse consequences.

In addition to these adverse consequences, there are unforeseen consequences of Subpart OOOOa. In West Virginia, and other states, facilities that were, prior to Subpart OOOOa, not subject to minor source permitting are finding themselves subject to state minor source permitting for the first time. Not only does that minor source permitting require them to expend limited resources on permitting fees (\$1000 to \$3000), but it exposes them to additional liability. These additional "compliance costs" were not contemplated or accounted for in the EPA's cost/benefit analysis of the LDAR requirements.

The Independent Producers petitioned the EPA to reconsider its decision regarding the inclusion of low producing wells in Subpart OOOOa and to address the incorrect definition of modification. As a part of the EPA's actions to stay the immediate implementation of the fugitive emissions requirements of Subpart OOOOa, the EPA should defer application of the fugitive emissions program on low producing wells and on refracturing of existing wells until it completes action on the pending petition for reconsideration.

**C. The EPA Must Re-evaluate the Costs of Compliance with More Representative Gas Prices and Assumptions.**

An Independent Operators<sup>7</sup> provided the following information regarding cost associated with the regulations. The Independent Operator administers approximately 1,000 wells with an average of 9 barrels of oil per day per well. As a result of the numerous regulations passed during the previous Administrations, the Independent Operator was forced to double its regulatory personnel and to contract an environmental company to help comply with the regulations. The Subpart OOOOa regulations are just another example of severe government overreach that will further drive costs up even with little benefit. The Independent Operator estimated it spends an average of \$1,363,000 per year to meet current state and federal regulations (about 4.3% of the total operating budget). If Subpart OOOOa regulations are implemented, the Independent Operator could easily spend \$2,500,000 to comply at all battery and well sites, suffering an increase in its operating budget of almost 8% in the first year and an increase of 3.1% in subsequent years. Considering the majority of the wells have a gas-oil ratio of 200 or less, this would mean that the Independent Operator would have to spend the equivalent of \$4.76/mcf of gas in the first year to modify batteries and equipment, and \$1.90/mcf of gas in following years to repair and constantly upgrade equipment. With existing gas contracts, gas production going forward would be uneconomical and potentially devastating. Currently, gas production due to processing fees and historically low prices is marginal, at best, with average gross prices at \$3.00 or less, and net prices at \$1.50 or less.

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<sup>7</sup> Individual members of the Independent Producers who wish to remain anonymous are referred to as "Independent Operator."

Most importantly, the cost of eliminating “fugitive” emissions is astronomically high. The Independent Operator mentioned above estimated reduction in emissions company-wide amounts to a decrease of about 14.4 mcf per day. In other words, the Independent Operator would spend \$4.76/mcf of fugitive gas to stop “potential” emissions, while the gas is worth less than \$3.00/mcf in the market! Then, the Independent Operator would spend \$1.90/mcf of fugitive gas on an ongoing basis to stop potential emissions. This makes no economic sense but is very real for many independent operators.

The EPA states that much of the methane and volatile organic compounds (“VOCs”) that are captured as a result of this regulation will be sold into the natural gas market. The EPA is expecting owners and operators to use the gas sales to offset compliance costs.

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

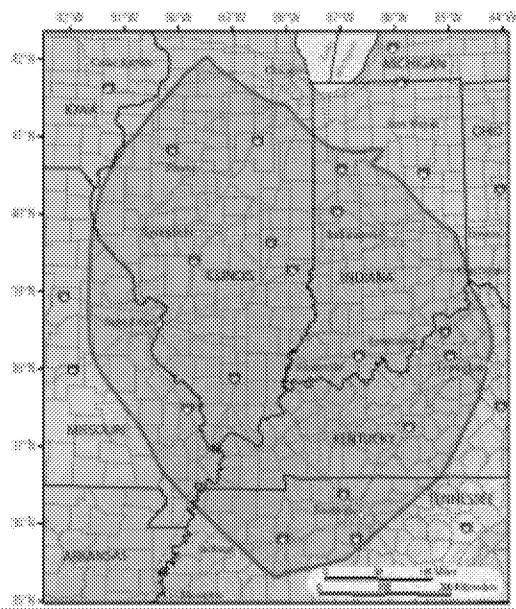
Many of the wells are drilled and produced in the Illinois Basin have a gas to oil ratio that is greater than the minimum threshold, but far below the quantity to justify a profitable project. The associated gas would need to be purified to make it pipeline quality, which is a significant investment for the small volume of produced gas. This particular company estimate that the construction of a gas processing facility could cost \$1 million to \$2.5 million, depending on gas quantity and quality.

Most operators in the Illinois Basin do not have gas gathering pipelines installed to enable collection and processing of the gas. Gas gathering lines could exceed \$500,000 per field to procure right of way, install the pipeline network, and install measurement instrumentation. There are a few interstate pipelines crossing the Illinois Basin, but in addition to the cost of building the gathering lines, the required tie-in and associated measurement equipment on an interstate pipeline may cost an additional \$250,000 to \$500,000.

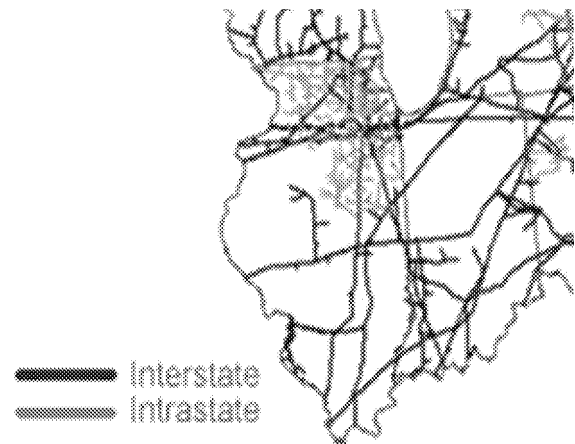
The Independent Operator evaluated several natural gas projects in the Illinois Basin. In every case, the projects were uneconomic because nitrogen is a common contaminant in the separated gas; and it is very expensive to remove. These projects do not produce enough gas to justify cryogenic nitrogen removal, which is the lowest cost option. The next best alternative is a pressure swing absorption (“PSA”) system or equivalent filtering method. With the produced gas, this results in an additional processing cost of approximately \$1.00/mcf. According to the EIA, the Henry Hub contract price for natural gas in June 2017 is approximately \$3.30/mcf. At the current gas price, any project that requires nitrogen removal will lose money for the investor.

The Independent Operator also performed Monte Carlo simulations around expected gas production, gas quality, compliance cost, operating cost, and product pricing. The outcome of these simulations shows that none of the projects were profitable (positive Net Present Value (“NPV”)) and any management team would reject the investment opportunity. Every well that Independent Operator may drill would only have additional compliance costs added to operation and no economic benefit would be realized from the typical well fields that they produce.

Many of the oil producers in the Illinois Basin do not process and sell gas that is associated with oil production because the processing costs are high relative to the volume of associated gas and because interstate pipelines are not readily accessible to the operators. Figure 1 (source: United States Geological Survey (“USGS”)) shows a map of the Illinois Basin and Figure 2 (source: EIA) shows interstate and intrastate natural gas pipelines in Indiana and Illinois.



**Figure 1. Illinois Basin**



**Figure 2. Illinois and Indiana Natural Gas**

Most of the oil wells do not have reasonable access to interstate or intrastate pipelines to transport produced gas to market. The cost to purchase right of way, install gas pipelines, tie into transportation pipelines, and install custody transfer instrumentation exceeds the economic benefit of selling the gas.

This particular Independent Operator’s interpretation of the EPA’s economics is that the EPA assumes installing a gas gathering pipeline is relatively low cost and that a right of way is

easy to procure. Instead, the Independent Operator's experience is that pipelines are expensive to install and maintain and acquiring a right of way ranges from easy to difficult.

Some land owners are accommodating while other land owners have no interest in having any type of pipeline on their property. The ability to secure a right of way has significantly impacted projects, ranging from additional cost to project cancelation. The effort and cost to secure rights of way should not be underestimated for any type of pipeline project.

### **SPECIFIC ISSUES RAISED IN THE NODA**

Throughout the NODA, the EPA asks specific questions regarding the technological, resource, and economic challenges with implementing certain aspects of Subpart OOOOa, including the fugitive emissions requirements, well site pneumatic standards, and the requirements for certification of closed vent systems by a professional engineer. The Independent Producers pulled from the NODA the specific questions and solicited their members for specific input. The Independent Producers tried to provide the necessary background information for the questions sought by the EPA. The questions presented to the members are reproduced below and the responses are summarized below the corresponding question.

**1. Should a phase-in period be implemented to allow a scale-up of the number of qualified professional engineers (to meet the rule's certification requirement by such professionals of (1) the closed vent systems routing emissions from various equipment and (2) technical infeasibility of routing emissions from a well site pneumatic pump to an existing control device or process onsite).**

- An Independent Operator suggests a phase-in period to provide the EPA the time necessary to address issues arising from ambiguities or internal contradictions that are latent within the drafting of the regulation. The regulation should be modified to encourage and permit additional Professional Engineers to practice in this area or eliminate the requirement for a Professional Engineer review.

The EPA provides the following definition of a Qualified Professional Engineer:

*Qualified Professional Engineer* means an individual who is licensed by a state as a Professional Engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge and experience to make the specific technical certifications required under this subpart. Professional engineers having these certifications must be currently licensed in at least one state in which the certifying official is located.

81 Fed. Reg. 35935 (June 3, 2016). A search of qualified Professional Engineers was conducted throughout the Illinois Basin. While this was not an exhaustive search, only one engineering firm has been identified that meets the requirements set forth by the EPA in Subpart OOOOa. The engineering firm does not primarily perform work in the Oil Exploration and Development business segment, but rather specializes in industry plant design and modifications. The engineering firm only meets the EPA's criteria because it performs flare system design for chemical plants and oil refineries, and because it has engineers licensed in one of the states in the Illinois Basin.

While the identified engineering firm may be available for some of the operators in the Illinois Basin, not all operators are permitted to work with the identified engineering firm. Per the EPA's definition, the Professional Engineer must be licensed in at least one state in which the certifying official is located. Several of the operators do not have operations in the state where the engineering firm is located, which eliminates this option for compliance.

Working with a large engineering firm to meet the EPA's compliance requirement is much more expensive than working with small engineering firms or independent Professional Engineers. Larger engineering firms have sufficient staffing and capabilities (*i.e.*, computer modeling software) to validate vent system design or technical infeasibility. Most of the smaller engineering firms or independent Professional Engineers are not able to afford the staffing or tools to perform the work that is required by the EPA.

The additional staffing and capabilities come at a cost to the operator. For example, a vent system conceptual design cost could exceed \$10,000, with the detailed design provided by the engineering firm exceeding \$100,000. The Professional Engineer certification for each installation may cost an additional \$3,000. The cost to install a vent system could be \$30,000 to \$60,000, based on the emission rate (*i.e.*, pipe and certified combustor sizing). With the typical cost of a new tank facility in the Illinois Basin being \$40,000 to \$50,000; the cost to meet the EPA's regulation will total more than the initial cost to construct the tank facility. Most small operators are not able to incur this type of additional cost for low producing wells. A low producing well might have the potential to emit 10 tons per year during initial production, but in less than a year is emitting less than 5 tons per year due to production decline. This regulation is excessively burdensome for small operators with a large inventory of low producing wells.

During the search for qualified Professional Engineers, several independent Professional Engineers and small engineering companies were interviewed. Of the few Professional Engineers that met the EPA's narrow definition, even fewer were willing to sign the EPA's liability statement. The EPA requires the Professional Engineer to execute and date the following statement for each technical infeasibility or each vent system design:

*I certify that the assessment of technical infeasibility was prepared under my direction or supervision. I further certify that the assessment was conducted and this report was prepared pursuant to the requirements of §60.5393a(b)(5)(iii). Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information.*

*I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted and this report was prepared pursuant to the requirements of subpart OOOOa of 40 CFR part 60. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete. I am aware that there are penalties for knowingly submitting false information.*

This search found that many Professional Engineers are not willing to accept the exposure to the EPA over a vent system design. Many of the Professional Engineers did not believe that the professional exposure was worth the risk of the EPA being involved with their practice. Several of the Professional Engineers are willing to forego the additional revenue in exchange for the reduced risk of not being open to an EPA audit.

Approximately 18 months after Subpart OOOOa was published to the Federal Register, only one qualified engineering firm could be identified within the three states that Illinois Basin crude oil is produced. A sufficient number of qualified Professional Engineers are not available for all of the operators throughout the three states. Additional time will not significantly improve the number of Professional Engineers to perform this work in the Illinois Basin.

- Range Resources indicated a phased-in period is recommended to allow for adequate time for a qualified Professional Engineer to become familiar with the closed-vent system (“CVS”) design that is being, or will be used to meet regulatory requirements. Technical feasibility of controlling emissions from a pneumatic pump is a function of its location, relative to a process or the control device. Pneumatic pumps that are near processes or control devices are more likely able to be controlled than units that are situated at greater distances. Alternatively, units that are located too far from available control options will likely not be technically feasible to control. To comply with the emission reduction requirements, site equipment layouts will need to be revised to strategically locate pneumatic pumps.

- Another Independent Operator suggests that these portions of the regulation should be considerably modified or eliminated from the regulation because they require operators to utilize resources that are not widely available. Qualified Professional Engineers are generally not available due to many of the requirements set forth by the EPA in the regulation. The few resources that are available are unnecessarily expensive for many operators to incur the additional compliance cost and still have a profitable project.
- LINN Energy (“LINN”) indicated the primary problem is that a lengthy time period is needed in order to get the adequate design approved. A cookie cutter design does not necessarily work and it often requires more time than the rule allows after the site is operational in order to properly design the CVS. Often a company will not even know if the design will work until the site is in routine operation. If the site is a horizontal drill with fracturing, it may take even longer to ensure that the CVS is adequately designed. This has been an on-going issue for operators since the rule has been implemented.
- Comments submitted by Tom C. Roberts, President, National Society of Professional Engineers (“NSPE”) points out “according to the National Council of Examiners for Engineering and Surveying, there were over 400,000 resident PE licenses and 400,000 nonresident licenses issued (a single individual can possess both) in 2016.” We agree that Professional Engineers provide a great service to American industry and that they have unique qualifications, expertise, and the legal and ethical capability to ensure public health, safety, and welfare in their designs. While our industry agrees that a great number of Professional Engineers are practicing in many engineering disciplines throughout the United States, very few of the Professional Engineers meet the EPA’s qualifications to provide certifications. Many of our companies employ Professional Engineers, but the Professional Engineer is unable to provide a service to their employer as a result of the narrow definition that the EPA provided for a Qualified Professional Engineer.

**2. How long a phase-in period is necessary in order to achieve the scaleup of qualified professional engineers?**

- Subpart OOOOa was published to the Federal Register approximately 18 months ago. One Independent Operator’s experience over that time period, is that none of the Professional Engineers that have been interviewed have worked towards meeting the EPA’s requirements to approve a vent system design or technical infeasibility. The Independent Operator believes additional time should be permitted to provide the EPA an opportunity to consider how to best change the regulation to meet operators needs and the EPA’s desire to ensure that vent systems are correctly implemented.

If the EPA desires to have Professional Engineers review and approve vent system designs or technical infeasibility, the EPA will need to find additional methods to incentivize engineers to meet the EPA's requirements. Currently none of the engineers that have been interviewed have indicated an interest to become qualified to meet EPA's requirements.

Two years would be a minimum, but five years would be a more realistic time horizon for EPA to evaluate options, complete the public comment period, issue the final ruling, and then provide a period for industry to prepare to implement the revised regulation. The 60 days that EPA originally provided to begin compliance was wholly inadequate.

- Another Independent Operator indicated that the certification is not currently a common industry practice, so probably two to four year time period would be more reasonable for this to become a common set of engineering calculations Professional Engineers in the petroleum industry routinely make.
- Range Resources indicated a minimum of 12 months is recommended – but 24 months would be preferred – for existing in-house staff to obtain professional credentials, or independent, third party Professional Engineers to comprehend design changes and operations of site specific designs and operations. Professional Engineer Examinations require months of preparation and are only offered bi-annually.

Contract engineers are required to adjust to changing production parameters as well pad designs are continuously evolving in response to equipment changes and different production techniques (*e.g.*, longer laterals). Standard designs are generally modified each year as data becomes more available for mechanical, electrical, and instrumental modifications/improvements.

**3. What challenges are sources experiencing difficulty in carrying out requirements of:**

**(i) securing the necessary equipment and/or personnel to conduct the required monitoring survey of fugitive emissions; and**

- One Independent Producer is experiencing a number of challenges in being able to comply with Subpart OOOOa fugitive emission survey requirements. The challenges will be discussed individually below:
  - a) Equipment Purchase Cost: Performing fugitive emission surveys as required by the EPA by purchasing equipment is not cost effective.

- 1) The cost to purchase equipment (*i.e.*, forward looking infrared (“FLIR”) camera) is approximately \$100,000, plus training and insurance cost. Most small operators in the Illinois Basin cannot justify the cost to purchase equipment and provide training for field staff.
  - 2) Many of the operators initially only have a small number of wells and tank facilities that meet the requirement for the LDAR program. The cost of equipment cannot be spread over a large number of wells and tank facilities.
  - 3) Most operators in the United States, not just the Illinois Basin, do not have available cash to purchase monitoring equipment and pay for training. The oil exploration and production business segment is entering into the fourth year of the most severe industry downturn since the 1980’s. Most operators are struggling to provide sufficient cash to operate their business.
- b) Contract Services for Compliance: Contracting with a third-party company to complete LDAR survey requirements.
- 1) Several companies have been interviewed to provide LDAR services to the Illinois Basin. No company in the Illinois Basin has been willing or able to purchase equipment to perform the inspection services due to the high cost of equipment and risk of not being able to cover the personnel, equipment, and training costs. All contract resources are located outside of the Illinois Basin.
  - 2) No companies are currently located in the Illinois Basin, which results in additional travel cost. Travel and Per Diem cost could add thousands of dollars in compliance cost with no additional benefit.
  - 3) If compliance equipment is rented without a trained operator (*i.e.*, rent a FLIR camera and train company employees to operate the camera), equipment is available for approximately \$1,000 per week. While this might appear to be the most cost effective option, it still requires an employee to be sent to training at a costs of \$3,000 to \$5000. The operator is also liable for damage to the equipment, potentially purchasing the \$100,000 camera if it is broken. This option also comes at an opportunity cost from the employee that is directed to complete compliance activities instead of other duties that provide other benefits to the operator.
  - 4) Contract inspection services is an option that is available to operators. Contract services have been quoted at \$350/hour, plus Per Diem with door to door service (*i.e.*, from the minute that the employee leaves their office until the minute that they

return to the office the operator is charged). It is estimated that two to four wells could be inspected per day in the Illinois Basin. At a cost of \$2,800, plus a daily Per Diem, this will add \$800 to \$1,600 in operating cost to each affected facility for every inspection performed. This cost is doubled because wells and tank facilities are required to be inspected every six months.

- c) Survey Frequency: The EPA requires operators to inspect wells and tank facilities within 60 days after startup or modification and every six months after the initial inspection. With the required inspection dates spread throughout the year, performing well site and tank facility inspections will be expensive because the operator will eventually have a continual requirement to inspect well sites and tank facilities. The way that the inspections are currently established, operators are not able to cost effectively contract an inspection company to perform LDAR inspections on all facilities twice per year. The EPA may consider changing the inspection requirement to have all well sites and tank facilities initially inspected using a low-tech method, such as soap bubbles, and then inspect the location within six months of startup using Optical Gas Imaging (“OGI”). Making this change will enable operators to have all well sites and tank facilities inspected at the same time by a qualified contractor.

The EPA also requires an inspection after each fugitive gas emission point has been repaired. This requirement will increase the cost of inspections because the inspection company will either have to spend time waiting for a leak to be repaired or traveling back to the location after a repair has been completed (which could be up to 30 days later). In either case, the subsequent inspection will result in considerable additional cost to the operator.

Updating the inspection requirements will enable existing inspection companies a greater opportunity to perform inspections for other companies. As the regulation is currently structured, an operator may have an inspection company contracted to perform all of their inspections. Due to the inspection requirements covering several months, the inspection company may be unwilling or unable to accept new clients due the inspection requirements of existing contracts.

- d) The documentation required during the monitoring survey of fugitive emissions will be the most time consuming and expensive part of the LDAR program. The EPA recently released the annual reporting template. In the template the EPA requires general information (19 fields) to be completed for each well or tank facility, 25 additional fields to be completed for LDAR monitoring at each affected tank facility, and 27 fields to be completed for LDAR monitoring each affected well facility. The data that are required for

the annual reports do not include all of the other data that the EPA requires operators to collect and store for five years during each fugitive emission survey. The documentation collection (not just for the LDAR section) is the most burdensome part of the entire regulation. Reducing the documentation that needs to be collected and stored should be included in the review.

The following information is required for each fugitive emission survey. Similar volumes of documentation are required for other sections of the rule.

- i. Date of survey
- ii. Beginning time
- iii. End time
- iv. Name of operator(s) performing the survey
- v. Training and experience of OGI operator
- vi. Ambient temperature
- vii. Sky condition
- viii. Maximum wind speed at the time of the survey
- ix. Monitoring instrument used (manufacturer and model number)
- x. Deviations from the monitoring plan, or a statement that there were no deviations from the monitoring plan
- xi. Number of components where fugitive emissions were detected
- xii. Type of components where fugitive emissions were detected
- xiii. Number of fugitive emission components that were not repaired as required in Section 60.5397a(h) (routine monitoring of fugitive emission components)
- xiv. Type of fugitive emission components that were not repaired as required in Section 60.5397a(h) (routine monitoring of fugitive emission components)
- xv. Number of difficult to monitor fugitive emission components monitored
- xvi. Type of difficult to monitor fugitive emission components monitored

- xvii. Number of unsafe to monitor fugitive emission components monitored
- xviii. Type of unsafe to monitor fugitive emission components monitored
- xix. Date of successful repair of fugitive emission component
- xx. Number of fugitive emission components placed on delay of repair
- xxi. Type of fugitive emission component placed on delay of repair
- xxii. Explanation for each fugitive emission component placed on delay of repair
- xxiii. Type of instrument used to resurvey repaired fugitive emission component that could not be repaired during the initial fugitive emissions findings

This list does not yield a benefit for the operator collecting the data or the EPA in reviewing the data. We believe that most of the data that are required can be eliminated and not impact the results of the fugitive gas emission survey.

- Devon Energy (“Devon”) suggests a revision to annual LDAR instead of semi-annual for well sites and compressor stations. In general, Devon has not had issues with securing personnel, equipment, etc. for LDAR as it is done in-house but is extremely expensive. Devon would revise the repair obligations to repair leakers within two years or *at next scheduled shutdown*.
- Range Resources also commented on the survey equipment being expensive: a single OGI camera typically costs \$85,000 to \$95,000 to purchase and requires annual maintenance that costs approximately \$3,000. Experienced corporate staff that have performed initial surveys often have additional ongoing environmental responsibilities so new staff will be required to conduct periodic surveys.
- Another Independent Operator indicated acquiring two (2) additional new OGI cameras took more time than it had anticipated. The Independent Operator anticipated a one-month delivery delay, but the OGI cameras were not received until two months after ordering.
- Internally EnerVest compared cost/benefits of undertaking the survey provisions in-house versus certified consultant LDAR surveyor. Although initially the person would most likely not be needed full time as drilling is slow, the company will still be looking at approximately \$100,000 to cover salary, truck, gas, medical, etc. The additional specific equipment and training would include:
  - FLIR camera cost: \$97,000, plus extra battery (\$165), software, etc.
  - Certification cost: 3-day course \$2,000, plus hotel and meals

- Suggested general maintenance (mainly lens cleaning): yearly \$1,200
- Suggested to trade in after 5 to 7 years, get credit for older model

In terms of hiring someone, EnerVest estimated an initial \$750 per facility, plus \$125 hourly charge for re-survey, plus hotel and mileage costs. There are also issues associated with the availability of a consulting LDAR surveyor: When a survey is cancelled due to inclement weather or other uncontrollable situations, the consultant may not have time to re-survey within the regulation re-survey guidelines. This can cause non-compliance for the company. For this reason, EnerVest has moved to obtain an in-house certified surveyor.

- Another Independent Operator had the following annual costs for complete LDAR on a per well basis:<sup>8</sup>
  - Rockies (WY and ND fields): \$1,200/well
  - Permian (oil fields): \$1,700/well
  - South Texas (gas field): \$600/well
  - Some regions per well costs will vary due to LDAR analogs being in place at the state level such that the repair “infrastructure” is already in place.
- Based on its history implementing the LDAR surveys, another Independent Operator calculated a per facility cost of approximately \$1,200 per well and that the cost does not go down appreciably if there are multiple wells per site.
- Another Independent Producer provided Statewide Area (“SWA”) Wyoming LDAR cost based on 2016 annual LDAR survey and includes both in-house and contractor costs
  - Assesses overall costs per ton reduction and incremental costs per ton reduction at annual, semi-annual, and quarterly monitoring frequencies
  - *70 sites, including 169 wells and approximately 84,000 components*
  - 428 fugitive emissions counted during annual OGI

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<sup>8</sup> This same Independent Operator identified another developing issue in the Permian field that Enardo tank valves are in very short supply. Operators order 50 for repairs/replacements but only get 5. So the larger point is that EPA should not just be concerned about challenges/limitations around LDAR camera, operators, repair contractors, etc. It is likely that, at least for the first few events, common types of leaks could result in bottlenecks in repair/replacement materials and thus in delays in the ability to conduct said repairs due to parts unavailability backlog.

- Associated counts of specific types of fugitive emission components based on equipment present on site
- Fugitive Emission Rates
  - Wyoming actual fugitive emission rate = 0.51%.
  - The EPA uses 1.18% fugitive emission rate from its OOOOa analysis
  - Colorado (CO) Regulation 7 and EPA erroneously reference fugitive emissions reductions in their technical documents
    - There are no semi-annual data from the CO Reg. 7 Study, yet the EPA referenced CO Regulation 7 document and used a 60% reduction rate.
    - The EPA utilized 80% reduction for quarterly monitoring, which is actually the reduction rate used in CO Regulation 7 for *monthly* monitoring.
    - This is important because EPA/CO underestimate annual monitoring benefit (51.7% vs. 40%) and overestimate reductions at semi-annual (57% vs. 60%) and quarterly (61% vs. 80%). This in turn, affects economic feasibility at various monitoring frequencies.

<b>Monitoring Frequency</b>	<b>Fugitive Emissions Monitoring (FEM) / LDAR Program Emissions Reduction</b>		
	<b>CO Regulation 7</b>	<b>EPA OOOOa</b>	<b>Wyoming Study</b>
Annually	40%	40%	51.7%
Semi-Annual	NA	60%	57.0%
Quarterly	60%	80%	61.0%
Monthly	80%	NA	NA

The following tables summarize the annual/semi-annual/quarterly Statewide Area LDAR costs:

**STATEWIDE AREA COST BASIS - ANNUAL, SEMI-ANNUAL and QUARTERLY LDAR MONITORING<sup>6</sup>**

	<b>Costs in</b>	
<b>IN HOUSE</b>	<b>\$1000's</b>	<b>Cost Description</b>
Camera	\$30.10	One IR Camera: \$92.25k + 13.39k 6° lens + \$8.5k Extended Warranty = 114.14k (\$2014) (Amortized @10% and 5 yr) = \$30.1k / yr/camera. One-Time Cost, includes 100 mm lens and insurance.
Maintenance/yr.	\$3.00	FLIR maintenance and shipping costs annually
FTE	\$120.00	Cost for 1 FTE = \$60/hr (\$120 K/yr)
Training/employee	\$1.00	\$5,000/yr over 5 years = \$1,000 annual cost
Vehicles	\$10.50	Cost for vehicle/year
Mileage Cost	\$0.70	\$ per mile
Recordkeeping/Reporting	\$90.00	Annual Monitoring = 0.75 FTE for Niobrara Program. Contractor = Internal costs for Recordkeeping/Reporting.
	\$120.00	Semi-Annual Monitoring = 1.0 FTE
	\$180.00	Quarterly Monitoring = 1.5 FTE
Parts/Labor Repair Costs (In House or Contractor)	\$0.31	Average Repair Cost per Leak
Mileage Traveled	3,579	Annual Monitoring - Total miles based on average in-house technician mileage per site
	7,158	Semi- Annual Monitoring
	14,316	Quarterly Monitoring
<b>CONTRACTOR</b>		
OGI Contractor Costs for Niobrara	\$0.90	\$900/site for OGI

**PAW LEAK DETECTION AND REPAIR (LDAR) COSTS ANALYSES - STATE WIDE AREA (SWA) - SUMMARY RESULTS**

**OVERALL COST ANALYSIS**

FREQUENCY	TOTAL LEAKS	LEAK RATE	EMISSIONS CONTROLLED (Tons VOC)		TOTAL COSTS (\$1,000's)		COST/TON VOC CONTROLLED (\$1,000's)			
			Based on Component Leaks Proportionate to Component Count	Based on Actual Leak Counts	Internal	Contractor	Internal		Contractor	
							Based on Component Leaks Proportionate to Component Count	Based on Actual Leak Counts	Based on Component Leaks Proportionate to Component Count	Based on Actual Leak Counts
Annual	207	0.25%	62.95	58.33	\$321.19	\$217.08	\$5.10	\$5.51	\$3.45	\$3.72
Semi-Annual	184	0.22%	69.40	64.30	\$346.66	\$303.05	\$4.99	\$5.39	\$4.37	\$4.71
Quarterly	167	0.20%	74.27	68.82	\$406.37	\$483.75	\$5.47	\$5.90	\$6.51	\$7.03

**INCREMENTAL COST ANALYSIS - SUMMARY RESULTS**

APPLYING ADJUSTED LEAK RATES(%) TO INTERNAL and CONTRACTOR COST DATA

FREQUENCY	^ DELTA INTERNAL COST/TON VOC REDUCED	^ DELTA CONTRACTOR COST/TON VOC REDUCED
Baseline	NA	NA
Annual	\$5.10	\$3.45
Semi-Annual	\$3.95	\$13.32
Quarterly	\$12.26	\$37.10

Based on Leaks Proportional to Component Counts

FREQUENCY	^ DELTA INTERNAL COST/TON VOC REDUCED	^ DELTA CONTRACTOR COST/TON VOC REDUCED
Baseline	NA	NA
Annual	\$5.51	\$3.72
Semi-Annual	\$4.26	\$14.38
Quarterly	\$13.23	\$40.04

Based on Actual Leak Counts

^ Delta Internal/Contractor Cost Per Ton VOC Reduced = Reduced Contractor Total Cost/Tons VOC Reduced for given frequency of monitoring

PAW FEM/LDAR OVERALL COST ANALYSES - STATE WIDE AREA (SWA)					
NO. LEAKS REDUCED (Frequency)	REDUCED VOC EMISSIONS	REMAINING LEAKS	REMAINING EMISSIONS	TOTAL COSTS	COST/TON VOC REDUCED
				Contractor	Contractor
428 (Start)	NA	NA	112.7		
221 (Annual)	58.25	207	54.42	\$217,084	\$3,727
244 (Semi-Annual)	64.22	184	48.45	\$303,052	\$4,719
261 (Quarterly)	68.73	167	43.94	\$483,745	\$7,039

### Incremental Emissions and Cost Analysis

- True measure of cost-effectiveness – assess costs and VOC reductions between FEM/LDAR monitoring frequencies (Incremental Analysis(“IA”))

APPLYING ADJUSTED LEAK RATES (%) TO CONTRACTOR COST DATA				
	No. Leaks Reduced (based on increased Monitoring Frequency)	TONS VOC REDUCED (based on increased Monitoring Frequency)	REDUCED CONTRACTOR TOTAL COST (based on increased Monitoring Frequency)	INCREMENTAL CONTRACTOR COST/TON VOC REDUCED
BASELINE	0	NA	NA	NA
ANNUAL OGI	221	58.25	\$217,084	\$3,727
SEMI-ANNUAL OGI	23	5.97	\$85,968	\$14,397
QUARTERLY OGI	17	4.51	\$180,693	\$40,095

\* Tons VOC Reduced = Original Tons VOC for each Frequency - Tons VOC from next lesser frequency - e.g. - Semi-Annual = Original Tons Annual OGI - Original Tons Semi-Annual OGI

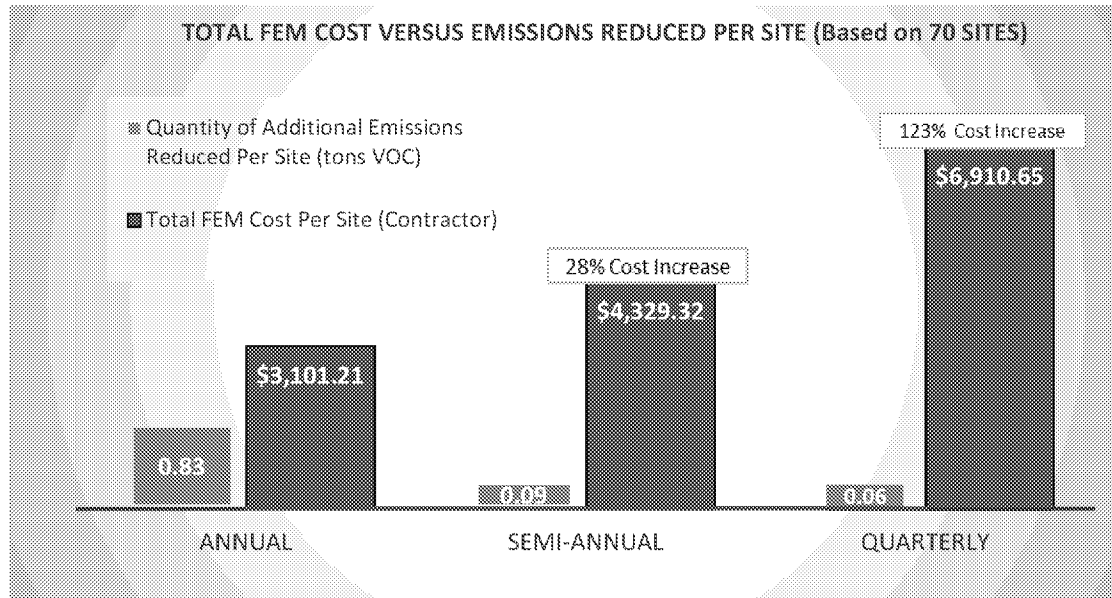
\*\* Baseline costs are assumed to be \$0 as there was no LDAR Program in place.

\*\*\* Reduced Contractor/Internal Total Cost = Cost of level of Monitoring - Cost of next lesser frequency of Monitoring - e.g. - Cost = Semi-Annual Original Cost - Annual Original Cost

Incremental Internal/Contractor Cost Per Ton VOC Reduced = Reduced Contractor Total Cost/Tons VOC Reduced for given frequency of monitoring

**Leak and Emissions Reductions Versus Total FEM/LDAR Cost Per Site<sup>7</sup>**

FREQUENCY OF MONITORING	LEAKS REDUCED PER SITE	Quantity of Additional Emissions Reduced Per Site (tons VOC)	Total FEM/LDAR Cost Per Site (Contractor)	COST INCREASE
ANNUAL	3.16	0.83	\$3,101.21	NA
SEMI-ANNUAL	3.49	0.09	\$4,329.32	28%
QUARTERLY	3.73	0.06	\$6,910.65	123%



**To summarize the data provided above:**

- The data presented above is typical of a mid-sized operation in the SWA. *Costs associated with small operators can be much higher per site* than are represented with this data.
- *Fugitive emissions ARE NOT a significant source at upstream oil and gas facilities (9% to 17%)* from which to extract further emissions reductions through increased frequency of FEM/LDAR monitoring with the intent of reducing VOC's as an ozone precursor for the foreseeable future.
- Subpart OOOOa will be reconsidered in the near future and the incorrect basis of establishing semi-annual FEM/LDAR monitoring frequency will be challenged -
  - *The Petroleum Association of Wyoming ("PAW") recommends that the Wyoming Department of Environmental Quality ("WYDEQ") await results of Subpart OOOOa reconsideration process to utilize new data and analyses to inform FEM/LDAR presumptive best available control technology for SWA in Wyoming.*
- Using conservative component population greenhouse gas ("GHG") emissions factors, actual leak counts and control efficiencies from the WY Study results in the following when compared to EPA/CO Regulation 7 analyses:
- Wyoming-based data results in:
  - Annual = 221 leaks or 51.7% reduction (40% using EPA)
  - Semi-Annual = 23 leaks or additional 5.3% reduction (20% reduction using EPA)
  - Quarterly = 17 leaks or 4% further reduction (20% reduction using EPA)
- Incremental costs per ton VOC reduced between increasing monitoring frequencies are not cost-effective:
  - Annual to Semi-Annual = Only 23 leaks and 5.97 tons VOC reduced at a cost of \$14,397/ ton
  - Semi-Annual to Quarterly = Only 17 leaks and 4.51 tons VOC reduced at a cost of \$40,095/ton VOC
  - Annual to Quarterly Frequency = \$25,445 /ton VOC reduced

- The EDF single-facility cost analysis using correct 60% control efficiency at quarterly monitoring = \$8,271 /ton VOC controlled (does not include cost of leak repair)
- Incremental costs per site are very high with little benefit (Note: lower emission control effect and much higher cost/ton if using AP-42 emission factors versus actual GHG factors used)
- Annual = Cost of \$3,101 per site, only 3 leaks and 0.83 tons VOC are reduced
- Semi-Annual = Cost of \$4,329 per site, only an additional 0.33 leaks and 0.09 tons VOC are reduced
- Quarterly = Cost of \$6,911 per site, only an additional 0.24 leaks and 0.06 tons VOC are reduced
- WYDEQ vs. PAW BACT Comparison – WYDEQ Meeting with PAW
  - Contains “WDEQ Analysis” – which only considered annualized capital costs and maintenance costs on camera
  - Added WYDEQ Analysis with operating costs – includes incremental costs for mileage and FLIR operation at each LDAR frequency. Basis of WYDEQ dropping reference to quarterly LDAR in pBACT for SWA.<sup>9</sup>
- (ii) phase-in period until November 30, 2018,<sup>10</sup> to connect well site pneumatic pumps to an existing control or process onsite.**
- From EnerVest’s experience, it is typically infeasible to connect vapors from pump to controls due to pressure differential, distance to control, design of facility with truck and other workover traffic. One would need another pump to pump the vapors to the control. For sites that have no controls, it is infeasible to add a control for the pneumatic pump. EnerVest uses solar pumps

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<sup>9</sup> See WYDEQ vs PAW BACT Comparison Excel Spreadsheet (attached as Exs. A1, A2 and A3).

<sup>10</sup> November 30, 2016 is the date identified in the proposed notice but that date is an artifact of the original proposal “[t]herefore, we are finalizing the compliance period to begin on November 30, 2016 to allow sufficient time for these necessary tasks to be completed.” 81 Fed. Reg. 35851 (June 3, 2016). Given the two-year stay proposal, this would presumably shift that date to November 30, 2018. The NODA in its estimated cost savings section gives a time frame of January 2018 to December 2019. Thus, the Independent Producers are presuming that the EPA’s proposed two-year stay (or phase-in window) presumably shifts that date to November 30, 2018.

but its facilities have lots of sun. Tree areas of the country may not be able to use solar. This part of the rule should be eliminated.

- Range Resources is of the opinion that for operators with large numbers of well locations without necessary control devices, the two-year phase-in period is appropriate.
- LINN has not been using well site pneumatic pumps, but if it were to use them, all of them will be classified as technically infeasible because the difference in pressure inside of the closed vent system in comparison to what is coming out of the storage tanks will be too great to design a safe system.
- Another Independent Operator commented on the Alternative Means of Emission Limitation (“AMEL”) Leak Repair Data – The EPA included leak costs in their cost analysis to justify semi-annual leak repair for NSPS Subpart OOOOa. The EPA assumed a 1.18% leak rate, equivalent to 3 leaks repaired for their 22 well site “Model Plant.” The EPA derived a total cost of \$597 for leak repair. We used an average cost of repair of \$310/leak based on cost input from our operations staff.
- Another Independent Operator has calculated the following costs for a voluntary program that is not the mandatory Subpart OOOOa program.

	2014	2015	2016
# of Inspections (# of wells surveyed)	3071	5592	5618
Component Leaks per well surveyed	0.18	0.15	0.15
Leaking Component % (Total Leaking components observed/Total estimated components at site)*.	0.06%	0.06%	0.06%
SWN SMART LDAR Implementation Cost  (Not OOOOa)	\$378,000	\$546,000	\$582,000
Component Gas Recovered MMSCF	90	135	126
Component Leak MCF/Well Surveyed	29	25	23
Component Leak Recovery Value (US \$)**	\$270,000	\$274,000	\$245,000

Source: Southwestern Energy, EPA Natural Gas STAR Methane Challenge Annual Implementation Workshop, October 25, 2017

\* 2234 components found leaking relative to an estimated component count of over 3.8 million between 2014 and 2016 at 14,281 wells.

\*\* 2014 based on \$3/MMSCF after royalty reduction, 2015 based on \$2.03/MMSCF after royalty reduction; 2016 based on \$1.95/MMSCF after royalty reduction

This Independent Operator anticipates there may be some increase in costs to comply with the administrative burden under the Subpart OOOOa LDAR relative to LDAR in its voluntary programs.

**4. Should EPA amend the above mentioned phase-in periods in the 2016 Rule instead of simply staying the requirements? What is the appropriate length of a phase-in period to address the challenges sources are experiencing in carrying out the requirements in the 2016 Rule?**

- One Independent Operator believes that a phase-in approach is more appropriate to address the concerns of operators and service industry that will be contracted to meet compliance requirements. The phase-in period should be at least two years, but could be up to five years based on the EPA's estimates of when equipment and service companies will be available to support operator's requirements.

The EPA's original compliance schedule required operators to meet initial compliance with Subpart OOOOa within 60 days of the regulation being published to the Federal Register. The rule provided a brief phase-in for operators to begin using equipment for Green Completions and one year to complete the initial fugitive gas inspections. At the same time, the EPA had more than a year to develop a method to accept the required data from operators' compliance activities. The EPA was several months late publishing the data collection template for operators to begin the reporting process.

The EPA was unable to meet the original compliance schedule, but only had a fraction of the work to complete. 60 days was not a realistic schedule for operators to achieve compliance with the many facets of this regulation. The Independent Operator believes that a minimum phase-in period of two years is possible, but a five-year phase-in period is more appropriate. Subpart OOOOa is an extensive and complex regulation that will require significant resources from industry to understand the regulation and to develop and implement compliance programs.

During the phase-in period, the EPA should continue to evaluate opportunities to reduce the burden placed on operators while continuing to meet the intent of the regulation. Opportunities to reduce the burden could include: reducing the volume of documentation that is required for every operator to collect, store, and report annually; implementing the low production well exemption that was included in the proposed rule; and implementing lower cost inspection tests such as soap bubble test for inspecting fugitive gas emission components.

- LINN believes that the proposed time periods are sufficient for implementation.
- Another Independent Operator favored staying the rule to provide regulatory certainty. Many of the requirements are ambiguous and overly burdensome. The regulated community would be required to comply with potentially two different versions of the rule and currently under an ambiguous rule that leaves many of the requirements uncertain.

- Range Resources suggested a minimum phase-in period of one year for a qualified Professional Engineer to become familiar with the field assets that are subject to the CVS requirements. The recent downturn in the production segment of the industry has created challenges in retaining experienced Professional Engineers to design and review newer CVS.

### **Fugitive Emissions Requirements**

5. **How is the availability of contractors and monitoring instruments, and the impact on owners and operators complying with the requirements at well sites and compressor stations impacting:**
  - (i) **requesting and receiving approval for the use of an AMEL and the applicability of the fugitive emissions requirements to low production well sites; and**
- The Independent Producers' position on the fugitive emissions requirements is set forth in the "General Comments," because of its importance to its members.
- Section 111(h) of the CAA outlines the procedures for getting AMEL work practices approved and requires the person applying to show "equivalency" in emissions reduction as compared to current practice in the rule. AMEL also requires a public notice of application in the Federal Register, with a comment period and an opportunity for public hearing. This process is labor intensive, time consuming and provides little incentive to use it. Adherence to Section 111(h) requirements is too burdensome, not feasible, and not necessary. The American Petroleum Institute ("API") overarching recommendation is that the pathway for approval for state equivalency and emerging technology not be required to adhere to Section 111(h).

### **Emerging Technology:**

New leak detection technologies are in development and various operators are partnering with manufactures to pilot new, cutting edge technologies. These technologies have the potential to be more effective and efficient at detecting leaks than methods approved under the rule. So that innovation is not stifled but rather encouraged, the EPA should provide a reasonable and streamlined pathway for approval under the rule. At a minimum, API recommends at a minimum that the EPA allow modeling to show performance of technology and/or "equivalency" in emission reduction, require only limited monitoring data to be collected, allow manufacture/vendor to apply for approval, and allow approved technology to be used for all sites subject to rule.

The Independent Producers suggest the following changes to Subpart OOOOa to allow more entities to utilize the AMEL provisions:

- Allow modeling to show performance of technology and/or “equivalency” in emission reduction (as required per Section 111(h));
- Require only limited monitoring data to be collected (just data that are needed to plug into model);
- Allow manufacture/vendor to apply for approval (not operator as its currently written); and
- Allow approval of technology to be used for all sites subject to rule (not a site-specific approval as rule is currently written)

**State Equivalent LDAR Programs:**

Additionally, state LDAR programs should be deemed alternative compliance, or “equivalent,” if the requirements are included in a state enforceable permit and meets minimum threshold requirements in regard to frequency and repair time frames. The EPA took a similar approach for tanks in Subpart OOOOa. Requiring operators to comply with two concurrent, yet different, LDAR programs with the same end goal, at the same sites is burdensome, costly and logistically difficult.

- Devon supports revising the AMEL provisions so that compliance with any similar state LDAR requirements meets Subpart OOOOa requirements in that state and support a much simpler AMEL for other LDAR technologies.

**(ii) for securing certified monitoring survey contractors and monitoring instruments**

- A number of the larger Independent Operators indicated they purchased the necessary equipment and received the necessary training to bring the operations in-house.
- One Independent Operator indicated securing equipment with a single contractor was feasible for the initial monitoring surveys in 2017. It took approximately 4 months with a single camera and operator to survey 70 LDAR facilities. It took about 3 months to plan this work out with the contractor.

In evaluating whether to purchase a camera the main bottleneck the company found was with recalibration time for the cameras. This summer it stood at about 3 months. Between the recalibration time and inclement weather days it appears a single camera will only be operational about half the year. While this did not affect the initial LDAR surveys, it would logically be a significant problem on the next round of surveys, which the industry has yet to experience.

The Independent Operator did not find any contractors who know how (but all had varied opinions) to comply with the rules and still much uncertainty on what is required and expected especially in regards to reporting and recordkeeping. Each company interviewed had a different view on the regulations and there is no consensus on what the 120 pages of text in Subpart OOOOa actually mean and require of well operators.

**6. Should the phase-in period be extended, and if so the appropriate length of the phase-in period to allow for an adequate buildup of the personnel and equipment required for meeting the fugitive emissions requirements? Does the impact of this requirement and any feasibility issues affect only a few sources or is this a systemic issue related to many sources?**

- One Independent Operator found that the availability of personnel and equipment, or lack thereof, in the Illinois Basin is systemic; this is a problem for all of the operators in the basin. All of the major exploration and production companies left the Illinois Basin decades ago. This basin only produces approximately 30,000 per day, which does not attract large companies or significant investment.

Most of the wells in the Illinois Basin are marginal/low production wells with low gas to oil ratios. Most of the wells require pumping units to be installed just to begin production because the reservoir pressure is very low. The feasibility to implement a basin-wide program with qualified fugitive gas emission inspection companies and qualified Profession Engineers is very low.

A minimum of a two-year phase-in period, with consideration to extend to five years would provide an opportunity for contractors to meet the needs of major basins around the United States and then begin to consider extending their business model into smaller basins around the country. At this point, none of the service companies that support major oil and gas production basins are interested in establishing a presence in legacy basins such as the Illinois Basin.

In addition to the Illinois Basin being a legacy basin, the oil and gas exploration and production business segment has been financially struggling to survive over the past three years. With

little indication that the financial stress that is currently applied to the industry being abated, most service companies are more focused on surviving than incurring the risk to expand into a new basins with small business growth potential.

- Range Resources is of the opinion that the phase-in period should be extended a minimum of 12 months to train additional, dedicated staff and/or consultants for surveys. Existing experienced staff have been used to fulfill initial regulatory requirements; however, additional trained staff or consultant resources will be needed to perform the ongoing periodic surveys. New OGI operators will require an eye exam to identify color blindness issues, safety training, instrument training, education in infrared theory and operation, process equipment operation, diagnostics, and software and report writing.
- Another Independent Operator is of the opinion the rule should be stayed until it is revised to provide regulatory clarity and reasonable reporting and recordkeeping requirements. The Independent Operator also believes that a reasonable phase-in time frame might be an annual percentage of surveyed facilities to allow companies to determine how to adequately comply (e.g., 10 facilities in 2018, 25% in 2019, 50% in 2020, 75% in 2021, and 100% by 2022).

7. **Applicability of the fugitive emissions requirements to third-party equipment at well sites which is ancillary to production (e.g., equipment such as meters owned by midstream operators). The 2016 Rule requires that all fugitive emissions components at a well site be monitored and repaired, but there has been confusion as to the appropriate scope of components that are included in the definition of the well site for the fugitive emissions requirements. EPA received feedback that ancillary midstream assets (e.g., meters) should be excluded from the fugitive emissions requirements because they are owned by legally distinct companies from the well site owner and operator and could have limited emissions. EPA is soliciting comment on this feedback, specifically:**

(i) **What legal and logistical issues could prevent midstream operators, or other operators of ancillary third-party equipment, from compliance with the 2016 Rule? What are suggestions for addressing this issue?**

- Devon supports the removal of the requirement for LDAR of third-party on-site equipment such as meter runs, etc., that is not owned by the operator of the well site or compressor station.
- One Independent Operator is of the opinion that the small number of midstream components and miniscule associated emissions at a well site do not justify additional separate regulation. There is no regulatory justification for aggregating these components and their emissions with

third-party controlled and operated assets. As such, midstream components should be exempt from the rule.

**(ii) What number of contracts that would need to be renegotiated and what is the associated burden/cost to the regulated community of doing so?**

- LINN believes this is huge burden and short coming of Subpart OOOOa. Hundreds of midstream contracts would need to be re-negotiated within the company in order to account for this level of compliance because LINN is not responsible for the maintenance of these meters or facilities and cannot even legally touch them. The contract would have to be amended in order to properly ensure compliance because existing contracts do not provide the company with the authority to dictate maintenance of these meters to the midstream companies.
- Similarly, MarkWest argues the EPA cannot force a party to aggregate it emission sources with a third-party by contract or any other vehicle. Aggregation principles should recognize the separation of third-party owned and operated assets. There is not an enforceable, constitutional method to make a third-party midstream operator combine its assets for permitting and/or monitoring purposes with a well operator.
- Another Independent Operator argued that the midstream gas contracts would have to be re-negotiated or at a minimum would place an additional \$2,000/year for a separate survey cost on each well site to third-parties. Many of these third parties could fall under the small business definition and would ultimately bear the costs.

**(iii) In light of the above, should EPA stay or otherwise extend the phase-in period as it applies to third-party equipment on well sites until after EPA has addressed this compliance issue?**

- During development of Subpart OOOOa, the EPA failed to recognize many of the complex issues that exist within the oil and gas exploration and production business segment. The EPA further developed a major regulation with a “one-size-fits-all” perspective in an effort to publish the regulation prior to the end of the Obama Administration instead of working with industry representatives to co-develop a comprehensive regulation. Many comments that were provided to the EPA through several venues (such as the Small Business Administration office or public comment period) were ignored by the Administration to meet the environmental agenda. As a result, the EPA and industry continue to expend vast resources to address issues with the regulation.

Addressing the interface between business entities will be a challenging issue for many companies to develop solutions. In most cases, this will not be a quick resolution as corporate

contract departments will need to develop options and select the best option available. Options will need to be reviewed by legal departments, which could substantially increase the time to implement solutions. Many of these reviews will take time and involve a variety of resources to implement a solution.

The interface between equipment of separate legal entities will create legal and logistical challenges that will need to be addressed to meet compliance requirements. When a shutdown occurs that will result in a financial loss (*i.e.*, shut in production), companies will need to develop solutions to address these occurrences. Not only will companies incur maintenance cost to address fugitive emissions, shutdown and startup costs must also be considered as considerable labor may be required to facilitate these events.

We recommend that the EPA rely upon data provided by operators and equipment manufacturers to perform a risk assessment for the typical equipment that exists at the interface point where companies will need to spend a time developing agreements related to addressing fugitive emissions. If data supports that the equipment has a high probability to emit fugitive emissions, companies should be required to develop solutions. If data shows that a low probability of fugitive emissions exists the EPA should exempt this equipment from leak detection and repair requirements while the equipment is operating.

- Given the length of time it takes to amend a contract, LINN believes a 3 or 4-year phase-in period would be better for this item.
- MarkWest believes the EPA should clarify that the rule applies to well site equipment owned by the well-site owner or operator, and that third-party equipment should not be considered part of the well-site, and should not require monitoring, absent the volume of emissions or components of such third-party equipment exceeding a certain threshold, the amount of such threshold to be the subject of a future valid rule-making process.
- Similarly, Range Resources believes the ancillary midstream assets and associated emission requirements should be defined separately from well site monitoring requirements.

Third-party equipment should not be the responsibility of the well site operator since employees are not permitted to operate or repair such equipment. In some cases, access is not available to third-party equipment due to security arrangements. The current regulations require repairs to be made as soon as practicable, which is typically during the monitoring survey and no later than 30 days after detection.

- 8. Regarding technical, safety, and environmental issues associated with the delay of repair provisions in the 2016 Rule, EPA proposed that if “repair or replacement [of**

**a leaking fugitive emissions component] is technically infeasible or unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled shutdown or within 6 months, whichever is earlier.” Stakeholders responded with concerns about “delays lasting longer than six months due to availability of supplies needed to complete repairs and information regarding the frequency of delayed repairs.” Some commenters also indicated that in some cases, requiring prompt repairs could lead to more emissions than if repairs were able to be delayed, for example if a well shut-in or vent blow-down is required. EPA has received feedback that requiring repair or replacement of fugitive emissions components during unscheduled or emergency vent blowdowns could result in natural gas supply disruptions, safety concerns, and increased emissions. Stakeholder feedback suggests that compliance with this provision could result in prolonged shutdowns impacting natural gas supply if necessary parts and skilled labor is unavailable, and avoidable blowdowns resulting in greater emissions than the leaking component. Feedback additionally indicates that these events may not necessarily result in the blowdown of all equipment located onsite and, thus, the equipment needing repair may not have been affected by the blowdown. EPA is soliciting comment on this feedback, specifically:**

- (i) What are the shutdown, shut-in, or blowdown scenarios that result in the technical, safety, and environmental issues described? And suggestions for addressing these issues.**
- Many operators are concerned with the safety issues associated with forced, unplanned shutdowns for marginal environmental gain. For safety and technical concerns, operators may have to shut-in production to replace thief hatches on tanks, where such tanks are connected by a common overhead vapor line that does not allow for isolation of tanks for repairs. The Independent Producers recommend Subpart OOOOa require (technically infeasible/unsafe) repairs at the next scheduled shutdown and *not* set an arbitrary six-month deadline.

See the language in 40 CFR § 60.482-9a(a) (NSPS Subpart VV for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry) and as relied upon by natural gas processing plants in NSPS Subpart KKK (40 CFR § 60.633(b)(3)(i)) and in NSPS Subpart OOOO (40 CFR § 60.5401(b)(3)(i)) providing, “[d]elay of repair for equipment for which leaks have been detected will be allowed if repair within 15 days is technically infeasible without a process unit shutdown. Repair of this equipment shall occur before the end of the next process unit shutdown.”

- One Independent Operator commented that it had encountered ESP cables around wells heads, compressor parts on the intake or discharge, main gas supply lines at production facilities. If any of these are found to have small leaks, a large amount of equipment, wells, and gas usually will be required to be shut-in. Almost all of this equipment is designed to be run continually usually requires some amount of fits and starts when re-starting which inevitably leads to gas discharges while each component re-pressurizes and re-starts. Each re-start exposes multiple employees to equipment start-up risks, which is almost always the most dangerous aspect of any facility operations. Shutting down and de-pressurizing each vessel is the only safe method to allow repairs to be made which is a trade-off for personal safety and startup emissions.
- Blowdowns themselves can result in significant emissions. Both on tanks and piping, and gathering lines. For example, in order to repair a small leak on a thief hatch, you may have to blowdown the tank, or if there is a series of production tanks, would have to blowdown all to repair one.

In regard to the delay of repair, if you shut down a site to do a repair, there may be more venting to do the repair than what was originally leaking.

Anytime gas is vented, there are safety concerns due to possible flammability and the potential release of hydrogen sulfide.

And the language re: repair at next shutdown or within 6 months creates a backlog and logistics mess trying to track all of this. Repair should simply be required at the next scheduled shutdown and the “or within 6 mo.” language should be removed.

**(ii) Should EPA stay or otherwise extend the phase-in period as it applies to equipment requiring delay of repair at well sites and compressor stations until after the EPA has addressed this compliance issue.**

- The Independent Producers strongly support a stay or an extension of the phase-in period while the EPA works to address the issues associated with this requirement. Any unscheduled shut down may cause problems from a technical, safety, or environmental standpoint because the cause of the unscheduled shutdown could be almost anything. If it is a safety or environmental concern, the first priority is always going to be these issues first, getting the site operational second and repairs to unrelated items third.

Further, these kinds of repairs are often difficult to schedule with roustabout crews with unscheduled shutdowns because you never know when they are going to occur nor how long they will last. You may have one tomorrow or in 6 months and sometimes the unscheduled shut down may last for only 30 minutes or it may last for days.

The EPA should remove the unscheduled shutdown part and only require the repair during the next planned shutdown. This would allow companies to better prepare and schedule repairs and alleviate all logistical or environmental, health and safety concerns.

- One Independent Operator supports the concept to not shut down and repair equipment that will result in greater emissions if the leaking fugitive emission component is not repaired when the leak occurs. Companies incur substantial risk and financial burdens when operating equipment is shut down for maintenance. The Independent Operator does believe that these occurrences will be relatively low frequency, which will minimize the environmental impact. When this type of event occurs, the operator should quantify the emissions from the existing fugitive emission source and the emissions as a result of the shutdown. If the leaking fugitive gas emission source is considerably less than the impact of shutting down equipment for repair, then temporary solutions should be explored to minimize the impact while safely operating the equipment.

#### **Well Site Pneumatic Pump Requirements**

9. **EPA proposed to stay for 2 years the requirements for well site pneumatic pump standards while it reconsiders the technical infeasibility exemption and the definition of “greenfield site.” EPA acknowledges that the technical infeasibility exemption that the EPA finalized in the 2016 Rule adopted a different approach than previously applied to the oil and gas industry and created an unanticipated and unnoticed distinction between “greenfield” (new development) and “non-greenfield” sites. Some stakeholders have suggested that this distinction has caused confusion among owners and operators on what sites qualify for the technical infeasibility flare. EPA is soliciting comment on:**
  - (i) **What are the technical constraints of new “greenfield” sites and specific site designs such as these which present challenges in implementing the well site pneumatic pump requirements in the 2016 Rule?**
- Range Resources believes the technical feasibility of controlling emissions from a pneumatic pump is a function of its location, relative to a process or the control device. Pneumatic pumps that are near processes or control devices are more likely able to be controlled than units that are situated at greater distances. Alternatively, units that are located too far from available control options will likely not be technically feasible to control. To comply with the emission reduction requirements, site equipment layouts will need to be revised to strategically locate pneumatic pumps.

- LINN states that a new field that is being developed will have numerous unknowns such as no available oil/water samples, no production information, no sour gas information, etc. It is virtually impossible to adequately design a system to handle these unknowns for any greenfield site. No matter how well the system is designed, it is going to have to be modified in the field in order to get it working properly and equipment will necessarily be shuffled on and off site. This process can easily take upwards of 6 months to a year and you may not have a good idea about how a greenfield site will work until you have drilled multiple wells in the area.
- Devon supports removing the “greenfield” and “brownfield” distinction for determining viability of controlling pneumatic pump emissions. Operators should be able to show technical infeasibility in all cases.
  - (ii) **Should EPA extend the phase-in period for 2 years (the time period the EPA estimates its reconsideration process and the issuance of the resulting rule would take), so that the EPA may provide the necessary clarification or revision in conjunction with its reconsideration process, thereby addressing all issues in one rulemaking?**

The Independent Producers support at least a two-year phase-in – it should be extended to 3 or 4 years.

- (iii) **Should EPA extend the phase-in period (and if so for what length of time) for the well site pneumatic pump requirements as an alternative to the proposed stay of these requirements?**

The Independent Producers support at least a two-year phase-in – it should be extended to 3 or 4 years.

### **Professional Engineering Certification Requirements**

10. **EPA proposed to stay for 2 years the requirement for closed vent system certification by professional engineer while the EPA evaluates the benefits, as well as the cost and other compliance burden, associated with this requirement. EPA received feedback that owners and operators had to reanalyze and potentially redesign the closed vent systems in order to meet this certification requirement. EPA received feedback from some stakeholders that owners and operators have struggled to obtain professional engineers to complete these certifications primarily because of a shortage of professional engineers certified in each state of operation with experience in the design of these systems. EPA is soliciting comment on:**

**(i) What is the availability of professional engineers qualified in each state of operation and experienced in the oil and gas field?**

Based on the responses from members of the Independent Producers, the answer is “it depends.” It depends on location and size of the company.

**(ii) What are the costs associated with completing the certification requirements in the 2016 Rule?**

The Independent Producers indicated completing the certification requirements cost between \$1,200 and \$2,500.

**(iii) What are the costs of reanalyzing and redesigning sites in order to comply with the requirements of the 2016 Rule?**

As indicated above – “it depends.” One Independent Operator provided the following rough estimates:

- Emissions/permit evaluations: \$2,000;
- New Flare cost: 20,000;
- Redesign existing well (vent line, scrubber pots): \$5,000 plus, if applicable, a new combustor and associated equipment; and
- Addition of by-pass flow meter: \$2,500 meter and \$1,500 additional equipment.

**(iv) Should EPA providing a period to phase in this certification period as an alternative to staying this requirement?**

The Independent Producers would prefer the certification provisions be removed in their entirety but a phase-in period is needed

If the EPA has any questions or concerns regarding the information and comments provided above, please do not hesitate to contact me.

Sincerely,

A handwritten signature in black ink, appearing to read "James D. Elliott". The signature is fluid and cursive, with a large initial "J" and "E".

James D. Elliott

cc: Bill Wehrum, EPA (via E-mail)  
Amanda Gunasekara, EPA (via E-mail)  
Elliott Zenick, EPA (via E-mail)  
Sarah Dunham, EPA (via E-mail)  
Steve Page, EPA (via E-mail)  
Peter Tsigotis, EPA (via E-mail)  
Kevin Culligan, EPA (via E-mail)  
David Cozzie, EPA (via E-mail)



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August 2, 2016

The Honorable Gina McCarthy, Administrator  
U.S. Environmental Protection Agency  
1200 Pennsylvania Avenue, N.W.  
Washington, D.C. 20460

**Re: Request for Administrative Reconsideration EPA’s Final Rule “Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources”**

Dear Administrator McCarthy:

The following trade associations hereby submit this petition for administrative reconsideration of the final rule entitled “Oil and Natural Gas Sector: Emission Standards for New, Reconstructed, and Modified Sources,” published at 81 Fed. Reg. 35824 (June 3, 2016) (“Subpart OOOOa” or “Methane NSPS”). We request that you take the time to review what and who these trade associations represent and not simply jump to the issues we are seeking reconsideration of. Many of these trade associations have been around since or before the 1950s. The trade associations represent the “independent” exploration and production companies – from the “mom and pop” operations to some of the larger producers in the country – but that is all they do and it is all they know. Subpart OOOOa, as finalized, will have a disproportionate impact on independents and especially independents that constitute “small business” under the Regulatory Flexibility Act. The issues raised in this petition fall into two categories: 1) issues that are entitled to reconsideration under Section 307(d)(7)(B) of the Clean Air Act (“CAA”), 42 U.S.C. § 7607(d)(7)(B), where it is impracticable to raise an objection during the period of public comment or if the grounds for such an objection arise after the public comment period (but within the time specified for judicial review), and if such objections are of central relevance to the outcome of the rule; and 2) issues the independents commented on, either through their trade association or as an individual company, that the U.S. Environmental Protection Agency (“EPA” or “Agency”) failed to address in the final rule and that will have devastating impacts to the exploration and production segment of the industry if not addressed.

The national and state level trade associations joining in and filing this petition for reconsideration, collectively referred to as the “Independent Associations,” are described below.

The Independent Petroleum Association of America (“IPAA”) is an incorporated trade association that represents thousands of independent oil and natural gas producers and service companies across the United States that are active in the exploration and production segment of the industry, which often involves the hydraulic fracturing of wells. IPAA serves as an informed

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West Virginia      North Carolina      Pennsylvania      Virginia

voice for the exploration and production segment of the industry, and advocates its members' views before the United States Congress, the Administration and federal agencies.

The American Exploration & Production Council ("AXPC") is an incorporated national trade association representing 29 of America's largest and most active independent oil and natural gas exploration and production companies. AXPC members are "independent" in that their operations are limited to exploration for and the production of oil and natural gas. Moreover, its members operate autonomously, unlike their fully integrated counterparts, which operate in additional segments of the energy business, such as downstream refining and marketing. AXPC members are leaders in developing and applying the innovative and advanced technologies necessary to explore for and produce oil and natural gas, both offshore and onshore, from non-conventional sources in environmentally responsible ways.

The Domestic Energy Producers Alliance ("DEPA") is a nationwide collaboration of 25 coalition associations, representing about 10,000 individuals and companies engaged in domestic onshore oil and natural gas production and exploration. Founded in 2009, DEPA gives a loud, clear voice to the majority of individuals and companies responsible for enduring work to secure our nation's energy future.

The Eastern Kansas Oil & Gas Association ("EKOGA") is a nonprofit organization founded in 1957 to become a unified voice representing the unique interests of eastern Kansas oil and gas producers, service companies, suppliers and royalty owners on matters involving oil and gas regulations, safety standards, environmental concerns and other energy related issues.

The Illinois Oil & Gas Association ("IOGA") was organized in 1944 to provide an agency through which oil and gas producers, land owners, royalty owners, and others who may be directly or indirectly affected by or interested in oil and gas development and production in Illinois, may protect, preserve and advance their common interests.

The Independent Oil and Gas Association of West Virginia, Inc. ("IOGA-WV"), is a statewide nonprofit trade association that represents companies engaged in the extraction and production of natural gas and oil in West Virginia and the companies that support these extraction and production activities. IOGA-WV was formed to promote and protect a strong, competitive, and capable independent natural gas and oil producing industry in West Virginia, as well as the natural environment of their state.

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 was formed in 1942 and historically has been an all-volunteer organization principally made up of representatives of oil and gas exploration and development companies (operators), however, it has enjoyed support and membership from pipeline, refinery, land acquisition, service, supply, legal, engineering and geologic companies or individuals. INOGA has been an active representative for the upstream oil and gas industry in Indiana and provides a common forum for this group. INOGA represents its membership on issues of state, federal, and local regulation/legislation that has, does and will affect the business of this industry. INOGA is a

501(c)(6) trade association incorporated as Non-Profit Domestic Corporation under the statutes of Indiana.

Since 1940, the International Association of Drilling Contractors (“IADC”) has exclusively represented the worldwide oil and gas drilling industry. IADC’s contract-drilling members own most of the world’s land and offshore drilling units that drill the vast majority of the wells producing the planet’s oil and gas. IADC’s membership also includes oil-and-gas producers, and manufacturers and suppliers of oilfield equipment and services. Through conferences, training seminars, print and electronic publications, and a comprehensive network of technical publications, IADC continually fosters education and communication within the upstream petroleum industry.

The Kansas Independent Oil & Gas Association (“KIOGA”) is a nonprofit organization founded in 1937 to represent the interests of oil and gas producers in Kansas, as well as allied service and supply companies. Today, KIOGA is a trade association with over 4,200 members involved in all aspects of the exploration, production, and development of crude oil and natural gas resources.

The Kentucky Oil & Gas Association (“KOGA”) was formed in 1931 to represent the interests of Kentucky’s crude oil and natural gas industry, and more particularly, the independent crude oil and natural gas operators as well as the businesses that support the industry. KOGA is comprised of 220 companies which consist of over 600 member representatives that are directly related to the crude oil and natural gas industry in Kentucky.

The Michigan Oil And Gas Association (“MOGA”) represents the exploration, drilling, production, transportation, processing, and storage of crude oil and natural gas in the State of Michigan. MOGA has nearly 850 members including independent oil companies, major oil companies, the exploration arms of various utility companies, diverse service companies, and individuals. Organized in 1934, MOGA monitors the pulse of the Michigan oil and gas industry as well as its political, regulatory, and legislative interest in the state and the nation’s capital. MOGA is the collective voice of the petroleum industry in Michigan, speaking to the problems and issues facing the various companies involved in the state’s crude oil and natural gas business.

The National Stripper Well Association (“NSWA”) was founded in 1934 as the only national association *solely* representing the interests of the nation’s smallest and most economically-vulnerable oil and natural gas wells before Congress, the Administration and the Federal bureaucracies. It is the belief of NSWA that producers, owners, and operators of marginally-producing oil and gas wells have a unique set of needs and concerns regarding federal legislation and regulation. NSWA is a member based trade association with nearly 800 members nationwide across 43 states.

The North Dakota Petroleum Council (“NDPC”) is a trade association representing more than 590 companies involved in all aspects of the oil and gas industry, including oil and gas production, refining, pipeline, transportation, and storage, as well as mineral leasing, consulting, legal work, and oil field service activities in North Dakota, South Dakota, and the Rocky

Mountain Region. Established in 1952, NDPC's mission is to promote and enhance the discovery, development, production, transportation, refining, conservation, and marketing of oil and gas in North Dakota, South Dakota, and the Rocky Mountain region; to promote opportunities for open discussion, lawful interchange of information, and education concerning the petroleum industry; to monitor and influence legislative and regulatory activities on the state and national level; and to accumulate and disseminate information concerning the petroleum industry to foster the best interests of the public and industry.

The Ohio Oil & Gas Association ("OOGA") is a trade association with over 2,600 members involved in all aspects of the exploration, production, and development of crude oil and natural gas resources within the State of Ohio. OOGA represents the people and companies directly responsible for the production of crude oil, natural gas, and associated products in Ohio.

Founded in 1955, the Oklahoma Independent Petroleum Association ("OIPA") represents more than 2,500 individuals and companies from Oklahoma's oil and natural gas industry. Established by independent oil and natural gas producers hoping to provide a unified voice for the industry, OIPA is the state's largest oil and natural gas association and one of the industry's strongest advocacy groups.

The Pennsylvania Independent Oil & Gas Association ("PIOGA") is a non-profit corporation that was initially formed in 1978 as the Independent Oil and Gas Association of Pennsylvania ("IOGA of PA") to represent the interests of smaller independent producers of Pennsylvania natural gas from conventional limestone and sandstone formations. Effective April 1, 2010, IOGA of PA and another Pennsylvania trade association representing conventional oil and natural gas producers, Pennsylvania Oil and Gas Association ("POGAM"), merged and the name of the merged organization changed to its present name. PIOGA's membership currently is approximately 500 members: oil and natural gas producers developing both conventional and unconventional formations in Pennsylvania; drilling contractors; service companies; engineering companies; manufacturers; marketers; Pennsylvania Public Utility Commission-licensed natural gas suppliers ("NGSs"); professional firms and consultants; and royalty owners. PIOGA promotes the interests of its members in environmentally responsible oil and natural gas operations, as well as the development of competitive markets and additional uses for Pennsylvania-produced natural gas.

The Texas Alliance of Energy Producers ("Texas Alliance") became a statewide organization in 2000 with the merger of two of the oldest oil & gas associations in the nation: the North Texas Oil & Gas Association and the West Central Texas Oil & Gas Association. The Texas Alliance is now the largest statewide oil and gas association in the country representing Independents. With members in 34 states, the Texas Alliance works on behalf of our members at the local, state, and federal levels on issues vital to the industry.

The Texas Independent Producers & Royalty Owners Association ("TIPRO") is a trade association representing the interests of 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 family businesses, the largest, publicly-traded independent producers, and mineral owners, estates, and

trusts. Members of TIPRO are responsible for producing more than 85 percent of the natural gas and 70 percent of the oil within Texas, and own mineral interests in millions of acres across the state.

Chartered in 1915, the West Virginia Oil and Natural Gas Association (“WVONGA”) is one of the oldest trade organizations in the State, and is the only association that serves the entire oil and gas industry. The activities of our members include construction, environmental services, drilling, completion, gathering, transporting, distribution, and processing.

The Independent Associations respectfully request the Agency reconsider the following issues.

**A. SECTION 307(D)(7)(B) RECONSIDERATION ISSUES**

- 1. The low production well (15 barrels of oil equivalent (“boe”)/day) exemption from leak detection and repair (“LDAR”) and reduced emission completions (“RECs”) requirements should be reinstated in the final rule and the requirements regarding low production wells should be stayed pending reconsideration.**

In the proposed rule, EPA sought comment on and proposed to exclude low production wells (*i.e.*, those with an average daily production of 15 barrel equivalents or less per day) from REC and LDAR requirements. 80 Fed. Reg. 56633-34, 56639, 56665 (Sept. 18, 2015). The trades representing the independents uniformly supported the low production well exemptions. Based on the preamble discussion of the low production well exemption, EPA listened to, understood, and accepted the arguments and comments set forth by “small entities” during the Small Business Advocacy Review Panel (“Panel”) process, in compliance with Section 609(b) of the Regulatory Flexibility Act as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (“SBREFA”). Small entity representatives (“SERs”), including trade associations that are part of this petition, met with the Panel, which included EPA personnel, on May 19, 2015, and June 18, 2015, and submitted written comments. The SERs’ message was clear – the potential REC and LDAR requirements would be the most onerous aspect of any additional controls on their operations. The SERs explained how and why these potential requirements would disproportionality impact small entities. The SERs explained the physical differences associated with low production wells (*e.g.*, primarily pressure and volume) and the marginal profitability of low production wells. EPA seemed to “get it” and stated in the preamble:

We believe the lower production associated with these wells [low production wells] would generally result in lower fugitive emissions. It is our understanding that fugitive emissions at low production well sites are inherently low and that such well sites are mostly owned and operated by small businesses. We are concerned about the burden of the fugitive emission requirement

on small businesses, in particular where there is little emission reduction to be achieved.

80 Fed. Reg. 56639. Numerous oil and natural gas trade associations, including many of the parties to this petition filed comments in support of the exemptions and the rationale behind them.

Despite the information provided to EPA during the SBREFA process and Final Report of the Panel, EPA reversed course in the version of Subpart OOOOa and did not provide the low production exemption from either the REC or LDAR requirements. In the preamble to Subpart OOOOa that “one commenter” stated that low production wells have the “potential” to emit high fugitive emissions; “another commenter” stated that the LDAR survey should be conducted quarterly or monthly; and “one commenter” provided an estimate that a “significant” number of wells would be excluded under the low production well exemption. What appears to be EPA’s principal reason for reversing course is that

[S]takeholders indicated that well site fugitive emissions are not correlated with levels of production, but rather based on the number of pieces of equipment and components. Therefore, we believe that the fugitive emissions from low production and non-low production well sites are comparable.

81 Fed. Reg. 35856. EPA’s rationale, that fugitive emissions are a function of the number and types of equipment, and not operating parameters such as pressure and volume, is inconsistent with EPA’s justification for what constitutes a “modification” for an existing well site. EPA assumes that fracturing or refracturing an existing well will increase emissions because of the additional production, *i.e.*, the additional pressure and volume. EPA cannot ignore the laws of physics to the detriment of low production wells in one instance and then “honor” them in another context to eliminate an “emissions increase” requirement in the traditional definition of “modification.”

The estimation or correlation of fugitive emissions with the number or types of components at low production versus non-low production wells was not discussed during the Panel process nor was comment sought by EPA in the proposed rule. If EPA proposed to correlate fugitive emissions at low production well sites with the number or types of components – in place of operating parameters such as line pressure and volume, independents would have been put on notice that additional information and comments were needed on the issue. No such comment was sought and EPA rationale and revocation of the low production well exemption is confounding. An administrative stay of the REC and LDAR requirements to low production wells is warranted pending outcome of the reconsideration proceeding. Although the effective date of the requirements has been extended 180 days, the impact of the regulations is immediate on low production wells. The marginal profitability will mean that many wells will be shut in instead of making the investment to conduct LDAR surveys. Similarly, low production wells that are currently in the planning stage will be reevaluated to take into consideration the

additional costs of RECs and it is likely that the plans to drill many wells will be scrapped. For the reasons set forth above, it is appropriate for EPA to grant reconsideration of this issue.

- 2. The requirement in Section 60.5375a of Subpart OOOOa that requires a separator be “onsite during the entirety of the flowback period” was not part of the proposal and imposes an unnecessary cost on many conventional wells drilled by independents.**

From the inception of the Subpart OOOO rulemaking, independent operators have informed the Agency that operating parameters during flowback of certain hydraulically fractured wells, often what is referred to as “conventional” wells, are such that a separator does not “work” – or as EPA has focused on is not technically feasible. EPA initially seems to understand this point and states:

... we do not have sufficient data to consistently and accurately identify the subcategory or types of wells for which these circumstances occur regularly or what criteria would be used as the basis for an exemption to the REC requirement such that a separator would not be required to be onsite for these specific well completions. In order to accommodate these concerns raised by commenters, the final rule requires a separator to be onsite during the entire flowback period for subcategory 1 wells (*i.e.*, non-exploratory or non-delineation wells, also known as development wells), but does not require performance of REC where a separator cannot function. We anticipate a subcategory 1 well to be producing or near other producing wells. We therefore anticipate REC equipment (including separators) to be onsite or nearby, or that any separator brought onsite or nearby can be put to use. For the reason stated above, we do not believe that requiring a separator onsite would incur cost with no environmental benefit.

81 Fed. Reg. 35881. Independent Associations take issue with the conclusion that requiring a separator onsite throughout the entire flowback period would incur no cost. The cost of having the separator on site is a significant cost and could be a limitation on the operations of certain operators. The existing regulations make clear that a separator must be utilized during the separation flowback stage and EPA has increased the record keeping and monitoring associated with the different stages of flow back. In addition to these requirements, there is the general duty clause to reduce emissions. The requirement to have a separator onsite throughout the flowback process is an unnecessary cost to many independent operators that provides no economic benefit. The proposed rule did not contemplate requiring a separator to be onsite throughout the flowback process and in fact inferred just the opposite. For the reasons set forth above, it is appropriate for EPA to grant reconsideration of this issue.

- 3. Subpart OOOOa added a variety of requirements associated with “technical infeasibility” that were not purposed or even mentioned in the proposed rule**

**that increase the cost of compliance with disproportionately impacts on independent operators.**

While the Agency has appropriately accepted the concept that it is not technically feasible to implement certain controls, EPA added a number of requirements in Subpart OOOOa that were not proposed or discussed in the proposed rule:

- The final rule requires that Professional Engineers (“PE”) certify connections of pneumatic pumps (§60.5393a) or closed vent systems (§60.5411a(d)) are not technically feasible at brownfield sites. The certification by a PE will add considerable cost with no demonstrated benefits. As with many of these requirements, the independent operators do not have the ability in-house to meet these requirements and are dependent on third-party contractors. As EPA pushes the envelope on new/additional requirements, economies of scale favor the larger operators and to the extent the contractors are available for hire, it comes at a premium cost for the smaller entities and/or independent operators.
- Without discussion in the proposed rule, the Agency has also removed the “technical infeasibility” option for controls at “greenfields.” Neither the proposed rule nor Subpart OOOOa define what constitutes a brownfield versus a greenfield. At some point in time a greenfield becomes a brownfield. Not only does the proposed rule fail to mention the concept of brownfield versus greenfield, Subpart OOOOa fails to provide any differentiation.
- The additional recordkeeping requirements added in Subpart OOOOa, at end of §60.5420a(c)(1)(iii)(A), associated with technical infeasibility, which were not part of the proposed rule, demonstrates that the Agency fails to understand that such requirements disproportionately impact small entities and many independent producers and operators.

The additional requirements associated with technical infeasibility were not only not addressed in the proposed rule, but the Agency failed to consider and address the disproportionate impact they would have on independent operators.

**B. ADDITIONAL ISSUES IN NEED OF REVISION**

The following issues were arguably addressed in some manner during the SBREFA and/or notice and comment process, but based on a review of the record, the Independent Associations believe they warrant additional discussion. The Independent Associations will provide the Agency additional information on these issues of concern.

1. The definition of “modification” as it relates to refractured wells and the LDAR requirements needs to be clarified and changed. The refracturing of wells does not necessarily mean emissions will increase. Emissions must increase to meet the NSPS definition of modification. As currently defined, Subpart OOOOa would unjustifiably subject “existing sources” that have not necessarily been modified to extensive and costly requirements.

2. Certain oil wells should be exempt from the LDAR requirements. Similarly, there should be a different definition of “low pressure well.”
3. There should be an “off ramp” for the LDAR requirements when existing wells or new wells become “low production” or marginal wells.
4. Although Subpart OOOOa provides a state equivalency process for LDAR programs, the procedure set forth in the regulations (§60.5398a) is overly burdensome to the point that states are unlikely to avail themselves of the provisions.
5. The digital/video LDAR related requirements (§60.5420a) are unnecessary and should be removed.
6. EPA should reinstate options to reduce the emission surveys to annual surveys. While certain operators might prefer the consistency of bi-annual surveys, many independent operators and small entities would still benefit from the ability to reduce survey frequency by demonstrating few/no leaks during consecutive surveys.
7. Extended implementation periods are necessary and warranted for small entities that lack the bargaining power and resources (and the in-house capabilities) to contract with consultants to undertake the surveys, testing and documentation required by Subpart OOOOa. .

The Honorable Gina McCarthy, Administrator

December 8, 2017

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As indicated above, the Independent Associations will provide additional information on the issues raised above. In the interim, if the EPA has any questions or concerns, please do not hesitate to contact me.

Respectfully submitted,

A handwritten signature in black ink, appearing to read "James D. Elliott". The signature is fluid and cursive, with a long horizontal stroke at the end.

James D. Elliott

Counsel to the Independent Associations

cc: Janet McCabe, EPA  
Peter Tsigotis, EPA  
David Cozzie, EPA  
Bruce Moore, EPA

Company Name:

Facility Name:

Wyoming Air Quality Standards and Regulations - Chapter 6, Section 2(c)(v)

**Best Available Control Technology Control Cost Analysis Worksheet**

(Based on Office of Air Quality Planning and Standards, EPA, OAQPS Control Cost Manual, Fourth Edition, EPA 450/3-90-006, January 1990, Section 2.3.2)

Reference No.	Site Rating (units)	Manufacturer	Model	Control Method	Controlled or Targeted Emission	Typical BACT (units)	Targeted Emission		
							without Control (TPY)	with Control (TPY)	
1		OGI Camera		Monitoring	VOC	50%	6.0	3.0	Semi-Annual
2		OGI Camera		Monitoring	VOC	60%	6.0	2.4	Quarterly
Reference No.	Interest Rate (i)	Control System Life (n)	Capital Recovery Factor (CRF)	Capital Investment (P)	Annual Maintenance Cost	Capital Recovery Cost (CRC)	Realized Economic Benefit		
1	0.1	5	0.264	\$110,000	\$6,250	\$29,018	\$0		
2	0.1	5	0.264	\$110,000	\$6,250	\$29,018	\$0		

"n" is the control system economic life, typically thought to be 10-20 years.

"i" is the considered the annual pretax marginal rate of return on private investment (i.e., what it may cost you to borrow the money).

P is the capital investment required to install the controls (i.e., equipment purchase cost, installation/retrofit cost, engineering, etc.).

Annual Maintenance Cost is the yearly costs to maintain the control effectiveness (i.e., cleaning, testing, etc).

WDEQ DOES NOT INCLUDE Operating Costs (i.e., Mileage, leak repair costs (EPA uses in OOOOa analysis), cost of paying contractor or internal camera operator, etc.). These are included in PAW Analysis

$CRC = CRF * P$

CRC = Capital Recovery Cost (Annualized cost of control over the life of the control)

CRF = Capital recovery Factor P = Capital Investment

$$CRF = i(1+i)^n / ((1+i)^n - 1)$$

i = Annual Interest Rate

n = Economic life of the control

**Total Annual Cost (TAC) = Annual Maintenance Cost + Capital Recovery Cost - Realized Economic Benefit**

**Cost to Control = TAC / (Targeted Emission Volume Without Control - Targeted Emission Volume with Control)**

Reference Number	TAC (\$)	Cost to Control (\$/Ton)
1	\$35,268	\$11,756
2	\$35,268	\$14,695
		(\$9,797 in WDEQ Analysis)

Does the control have "Economic Reasonableness" and "Technical Practicability"?

The cost to control under the 2010 O&G Guidance ranged from a low of \$6,300 per ton of VOCs to an upper bound of \$14,700 per ton of VOCs.

Based on the cost range, shown above, semi-annual and quarterly monitoring would be cost-effective for VOC emission control

Company Name:

Facility Name:

Wyoming Air Quality Standards and Regulations - Chapter 6, Section 2(c)(v)

**Best Available Control Technology Control Cost Analysis Worksheet**

(Based on Office of Air Quality Planning and Standards, EPA, OAQPS Control Cost Manual, Fourth Edition, EPA 450/3-90-006, January 1990, Section 2.3.2)

Reference No.	Site Rating (units)	Manufacturer	Model	Control Method	Controlled or Targeted Emission	Typical BACT (units)	Targeted Emission		
							without Control (TPY)	with Control (TPY)	
1		OGI Camera		Monitoring	VOC	50%	6.0	3.0	Semi-Annual
2		OGI Camera		Monitoring	VOC	60%	6.0	2.4	Quarterly

Reference No.	Interest Rate (i)	Control System Life (n)	Capital Recovery Factor (CRF)	Capital Investment (P)	Annual Maintenance Cost	Annual Operating Costs	Capital Recovery Cost (CRC)	Realized Economic Benefit
1	0.1	5	0.264	\$110,000	\$6,250	\$2,505	\$29,040	\$0
2	0.1	5	0.264	\$110,000	\$6,250	\$65,011	\$29,040	\$0

"n" is the control system economic life, typically thought to be 10-20 years.

"i" is the considered the annual pretax marginal rate of return on private investment (i.e., what it may cost you to borrow the money).

P is the capital investment required to install the controls (i.e., equipment purchase cost, installation/retrofit cost, engineering, etc.).

Annual Maintenance Cost is the yearly costs to maintain the control effectiveness (i.e., cleaning, testing, etc).

**WDEQ DOES NOT INCLUDE Operating Costs in Analysis (i.e., Mileage/Vehicle, Leak Repair Costs, recordkeeping and reporting, OGI operator costs, etc.**

EPA uses all of these costs in OOOOa and CTG cost analyses.

Additional Operating Costs include:

Operating Cost	Annual	Semi-Annual	Quarterly
Travel/Vehicle	\$13,005	\$15,511	\$20,521
Repair Costs	\$64,170	\$57,040	\$51,770
Contractor/Employee	\$120,000	\$120,000	\$180,000
Recordkeeping/Reporting	\$90,000	\$120,000	\$120,000
<b>Totals</b>	<b>\$133,005</b>	<b>\$135,511</b>	<b>\$200,521</b>
<b>Incremental Cost</b>	<b>NA</b>	<b>\$2,505</b>	<b>\$65,011</b>

$$CRC = CRF * P$$

CRC = Capital Recovery Cost (Annualized cost of control over the life of the control)

CRF = Capital recovery Factor P = Capital Investment

$$CRF = i(1+i)^n / (1+i)^n - 1$$

i = Annual Interest Rate

n = Economic life of the control

**Total Annual Cost (TAC) = Annual Maintenance Cost + Operating Costs + Capital Recovery Cost - Realized Economic Benefit**

**Cost to Control = TAC / (Targeted Emission Volume Without Control - Targeted Emission Volume with Control)**

Reference Number	TAC (\$)	Cost to Control (\$/Ton)	
1	\$37,795	\$12,598	Semi-Annual
2	\$100,301	\$41,792	Quarterly

Does the control have "Economic Reasonableness" and "Technical Practicability"?

The cost to control under the 2010 O&G Guidance ranged from a low of \$6,300 per ton of VOCs to an upper bound of \$14,700 per ton of VC

Based on the cost range, shown above, semi-annual and quarterly monitoring would be cost-effective for VOC emission control

**SEMI- ANNUAL COSTS**

<b>IN HOUSE</b>		<b>Cost Description</b>
Camera	\$30,100	One IR Camera: \$92.25k + 13.39k 6° lens + \$8.5k Extended Warranty = 114.14k (\$2014) (Amortized @10% and 5 yr) = \$30.1k / yr/camera. One-Time Cost, includes 100 mm lens and insurance.
Maintenance/yr	\$3,000	FLIR maintenance and shipping costs annually
FTE	\$120,000	Cost for 1 FTE = \$60/hr (\$120 K/yr)
Training/employee	\$1,000	\$5,000/yr over 5 years = \$1,000 annual cost
Vehicles	\$10,500	Cost for vehicle/year
Mileage Cost	\$0.70	\$ per mile
Recordkeeping/Reporting	\$120,000	1 FTE for Niobrara Program. Contractor and Internal costs are the same for Recordkeeping/Reporting.
Parts/Labor Repair Costs (In House or Contractor)	\$310	Average Repair Cost per Leak (Per Mike Genzler 8/19/15) from NW Fetter Pad 15-33-71 \ Pad LDAR Costs Analysis (9/18/15). See Repair Costs T
Mileage Traveled	7,158	Total miles based on average in-house technician mileage per site = 140 Inspections (70 sites x 2 times/year)
<b>CONTRACTOR</b>		
OGI Contractor Costs for Niobrara	\$900	\$900/site for OGI

**QUARTERLYL COSTS**

<b>IN HOUSE</b>		<b>Cost Description</b>
Camera	\$30,100	One IR Camera: \$92.25k + 13.39k 6° lens + \$8.5k Extended Warranty = 114.14k (\$2014) (Amortized @10% and 5 yr) = \$30.1k / yr/camera. One-Time Cost, includes 100 mm lens and insurance.
Maintenance/yr	\$3,000	FLIR maintenance and shipping costs annually
FTE	\$120,000	Cost for 1 FTE = \$60/hr (\$120 K/yr)
Training/employee	\$1,000	\$5,000/yr over 5 years = \$1,000 annual cost
Vehicles	\$10,500	Cost for vehicle/year
Mileage Cost	\$0.70	\$ per mile
Recordkeeping/Reporting	\$180,000	1.5 FTE for Niobrara Program. Contractor and Internal costs are the same for Recordkeeping/Reporting.
Parts/Labor Repair Costs (In House or Contractor)	\$310	Average Repair Cost per Leak (Per Mike Genzler 8/19/15) from NW Fetter Pad 15-33-71 \ Pad LDAR Costs Analysis (9/18/15). See Repair Costs T
Mileage Traveled	14,316	Total miles based on average in-house technician mileage per site = 280 inspections (70 sites x 4 times/year)
<b>CONTRACTOR</b>		
OGI Contractor Costs for Niobrara	\$900.00	\$900/site for OGI

**MILEAGE ESTIMATE BASIS:**

**NSPS OOOOa Comment**

**Vehicle Costs**

All costs in \$1000's/ Reflect Annual costs	Niobrara
	Crude Oil
	Regulatory Costs
Total Mileage Traveled (434 site visits)	22,190
Travel (10.5K/vehicle and fuel/maintenance)	\$26.03

**ASSUMPTIONS**

	Cost	Cost Description
Vehicles	10,500	cost for vehicle/year ^Niobrara includes both FTE and Contractor Mileage
Mileage	0.7	\$ per mile

434 total site visits per year = 22,190 miles.

70 x 2 = 140 visits/yr semi-annually / 434 visits/yr \*22,190 miles = 7,158 miles semi-annually

70 x 4 = 280 visits/yr quarterly / 434 visits/yr \*22,190 miles = 14,316 miles quarterly