



June 16, 2014

The Honorable Gina McCarthy, Administrator
U.S. Environmental Protection Agency
EPA West (Air Docket), Room 3334
1301 Constitution Ave., NW
Washington, DC 20004

Submitted via email to oilandgas.whitepapers@epa.gov

RE: Comments of the Independent Petroleum Association of America and Western Energy Alliance on White Papers on Methane and VOC Emissions in the Oil and Natural Gas Sector per the Climate Action Plan Strategy to Reduce Methane Emissions

Dear Administrator McCarthy:

The Independent Petroleum Association of America (“IPAA”) and Western Energy Alliance (“the Alliance”) appreciate the opportunity to provide comments on the United States Environmental Protection Agency’s (“EPA”) White Papers on Methane and VOC Emissions (“White Papers”) which were released for external peer review on April 15, 2014. The White Papers focus on technical issues relating to potentially significant sources of emissions in the oil and natural gas sector. While EPA has not opened a docket and the release of the documents for “comment” does not constitute formal rulemaking pursuant to the Administrative Procedure Act, EPA requested input from the public, including “technical information and data,” by June 16, 2014. According to EPA, the White Papers and input from the peer review panels and general public will serve as the basis for public policy decisions regarding potential reductions in methane emissions from the oil and natural gas sector.

IPAA represents the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts, that will most directly be impacted by EPA policy decisions to regulate methane directly from the oil and natural gas sector. Independent producers develop 95 percent of domestic oil and gas wells, produce 68 percent of domestic oil and produce 82 percent of domestic natural gas. Historically, independent producers have invested over 150 percent of their cash flow back into domestic oil and natural gas development to find and produce more American energy. IPAA is dedicated to ensuring a strong, viable domestic oil and natural gas industry, recognizing that an adequate and secure supply of energy is essential to the national economy.

The Alliance represents over 480 companies engaged in all aspects of environmentally responsible extraction and production of oil and natural gas across the West. The Alliance represents independent producers, most of which are small businesses with an average of fifteen employees. Alliance members are committed to reducing emissions from their operations and

consistently employ best industry practices, whether mandated by regulations or voluntary, and have an economic incentive to conserve methane wherever possible.

The five White Papers cover the following types of sources or activities within the oil and natural gas sectors: (1) compressors; (2) emissions from completions and ongoing production of hydraulically fractured oil wells; (3) leaks from natural gas production, processing, transmission, and storage; (4) liquids unloading; and (5) pneumatic devices. The White Papers are organized in generally the same fashion, with sections reviewing the available data on emissions from the particular subsector, assessing the existing technologies or methods to reduce emissions from that subsector, and setting forth a set of “charge” questions posed by EPA to the peer reviewers. The comments below provide responses to these “charge questions” for each of the five White Papers.

An overarching comment on the White Papers and the process is that it has been rushed – and the charge questions reflect that process. In a number of places, our answers are simply “no” or “not aware of additional information.” Such a response is often indicative of a confusing question or a question that lacks understanding of oil and natural gas processes. Moreover, many of the questions appear leading and foreshadow EPA’s intentions. Ostensibly this process was started because EPA became aware of new studies or data on VOC and methane emissions and wanted to evaluate that data. IPAA and the Alliance support EPA’s efforts to understand the issues associated with methane emissions. The truncated process implemented by EPA and the Administration is unlikely to lead to sound policy decisions. We encourage EPA to take additional time to gather more information or have the integrity to simply state it does not have enough information at this point to make sound policy decisions. IPAA and the Alliance look forward to working with EPA to improve its knowledge and understanding of the complexities associated with emissions and emission controls for these types of sources. IPAA and the Alliance believe that collaboration between EPA and the regulated community will result in workable regulations that are both cost-effective and protective of the environment.

In addition, increased natural gas electricity generation is the primary reason the United States has reduced greenhouse gas (“GHG”) emissions more significantly than any other industrialized country. Making natural gas development more expensive by expanding federal regulation could decrease that climate change success over time, as decreased supply drives prices that result in less natural gas power generation. The oil and natural gas industry has delivered significant GHG reductions through voluntary means, and is no longer the largest source of U.S. methane emissions. The industry voluntarily reduced methane emissions by 40% between 2006 and 2012, according to EPA’s most recent GHG inventory, a success story accomplished without a federal mandate. Oil and natural gas companies developed green completions and other technologies that have reduced emissions significantly, and as adoption rates continue to climb, we anticipate even more emissions savings. Our success shows that new federal regulations are not necessary. Overly prescriptive regulation can actually be counterproductive to technical innovation.

A. Comments on Compressors:

1. ***Please comment on the national estimates of methane emissions and methane emission factors for vented compressor emissions presented in this paper. Please comment on the activity data and the methodologies used for calculating emission factors presented in this paper.***

We note that most of the studies in the White Paper are focused on the midstream and downstream sectors of the oil and natural gas industry. The compressors used at oil or natural gas production sites are smaller reciprocating compressors that operate at lower pressures. Thus they have much less potential for emissions than larger compressors in other parts of the industry. Unfortunately, we are not aware of a study that focuses on the upstream sector of the industry.

2. ***Did this paper appropriately characterize the different studies and data sources that quantify vented emissions from compressors in the oil and gas sector?***

The White Paper should specifically note that the only emissions study which sampled a significant number of reciprocating compressors at oil and gas sites (1996 GRI/EPA) showed low vent rates from compressors located at oil and gas production sites.

3. ***Did this paper capture the full range of technologies available to reduce vented emissions from reciprocating compressors and wet seal centrifugal compressors at oil and gas facilities? In particular, are there other options for reducing emissions at existing reciprocating or centrifugal compressors? For example, the EPA is aware of “low emissions packing” for reciprocating compressors but has no detailed information on this technology.***

Routine rod packing monitoring by operations & maintenance personnel or automated monitoring techniques and systems are available. Low emission packing will likely work well in some applications, if fully evaluated and designed properly on a case-by-case basis. However, low emission packing is expensive to install and maintain. For low emission packing to be a cost effective technology, any regulation would need to have an option for a managed inspection/maintenance program, as opposed to a set time interval replacement interval, to take advantage of the low emission packing’s potentially longer life span.

4. ***Did this paper appropriately characterize the emissions reductions achievable from the emissions mitigation technologies discussed for reciprocating compressors and wet seal centrifugal compressors?***

The White Paper does not critique the assumptions used in the 2014 ICF/EDF paper for their cost/benefit analysis. The ICF paper misapplies the 57 scf/hr/cylinder average emissions factor for compressors in the gas processing and transmission sectors obtained from the 1996 GRI/EPA study. The 57 scf/yr-cylinder factor is a statistical average from a large measured data set which, theoretically, should include emissions

from rod packing at various years of life, from almost new to close to end of life. This average emissions factor should be applied in a cost/benefit analysis in the method used by EPA in the Technical Support Document (“TSD”) for Subpart OOOO.

5. *Did this paper appropriately characterize the capital and operating costs for the technologies discussed for reduction of vented emissions from reciprocating compressors and wet seal centrifugal compressors?*

The White Paper cites a cost of \$1,620 per cylinder to replace the rod packing rings for a reciprocating compressor. This is a 2006 based dollar cost from EPA Natural Gas STAR that was also used in the TSD for Subpart OOOO and is too low. The White Paper also cites a cost of \$5,000 per cylinder for rod packing replacement from the 2014 ICF/EDF paper. This is a more up to date and accurate cost figure.

6. *If there are emissions mitigation options for reciprocating and centrifugal compressors that were not discussed in this paper, please comment on the pros and cons of those options. Please discuss the efficacy, cost and feasibility for both new and existing compressors.*
7. *Are there technical limitations that make the replacement of wet seals with dry seals impractical at certain existing centrifugal compressors?*
8. *Are there technical reasons why an operator would use a wet seal centrifugal compressor without a gas recovery system?*
9. *Are there technical limitations that make the installation of gas capture systems at certain reciprocating compressors impractical?*

The use of a vapor recovery system (“VRU”) or flare to collect vapor from rod packing vents requires a careful process design and safety review. Some factors that have to be considered are: not getting air into the system; minimizing pressure buildup in the distance piece; and automatic venting when the VRU or flare goes down. Due to the low pressures encountered on reciprocating compressor distance pieces, routing these vapors to a VRU is not possible unless the VRU is located close to the compressor, which would mean multiple VRUs for facilities with multiple compressors. Therefore, use of a VRU or flare recovery system would need to be done on a case by case basis by the operator to determine technical feasibility, cost, and safety.

10. *Please comment on the prevalence of the different emission mitigation options in the field.*
11. *Given the substantial benefits of dry seal systems (e.g., lower emissions, less maintenance, and higher efficiency), are you aware of situations where new wet seal centrifugal compressors are being installed in the field? If so, are there specific applications that require wet seal compressors?*

12. Are there ongoing or planned studies that will substantially improve the current understanding of vented VOC and methane emissions from reciprocating and centrifugal compressors and available techniques for increased product recovery and emissions reductions?

We are not aware of ongoing or planned studies.

B. Comments on Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production:

Before addressing the charge questions, we would like to make a few overarching comments that summarize our position related to hydraulically fractured oil well completions and associated gas during ongoing production. As an initial matter, the White Paper on this topic is not clear as to whether these questions apply to new sources, existing sources or recompletions. The responses are likely to vary considerably, with considerable differences for new sources versus existing sources. Additionally, the White Paper is not clear as to what constitutes a “hydraulically fractured oil well.” The White Paper cites but does not necessarily endorse the UT Study gas to oil ratio of 12,5000 scf/barrel as a cut point. EPA’s New Source Performance Standards Subpart OOOO did not define the difference and it is our understanding that EPA intends to propose some clarification of a “gas well” shortly in a second round of reconsideration rulemaking. A very large percentage of hydraulically fractured wells co-produce oil and gas. It also appears that EPA is relying on studies and statistics based primarily on what are considered “gas wells” and then extrapolating the results to oil well reduced emission completions (“RECs”). It is not that simple due to the different characteristics and operational procedures between gas wells and oil wells and EPA needs to more clearly articulate its assumptions with regard to the data presented in the White Paper. Finally, we question the need or benefit of EPA requiring reduced RECs or combustions devices/flares¹ at oil wells as operators are already engaged in such practices at a majority of the wells. There is a clear economic incentive to capture as much of the gas as possible and where it is not possible to capture the gas, safety concerns for the personnel at the well site drive the installation of flares. It is a matter of economics and common sense—if the gas can be captured economically, it will be. If it cannot be captured economically, and it is present in sufficient quantities to represent a safety concern, it is flared. A “one-size-fits-all” requirement for RECs or flares is unnecessary and will disproportionately affect marginal wells, low pressure wells and energized wells.

1. Please comment on the national estimates and per well estimates of methane and VOC emissions from hydraulically fractured oil well completions presented in this paper. Are there factors that influence emissions from hydraulically fractured oil well completions that were not discussed in this paper?

See the comments above, as they pertain to EPA’s data sources and estimates. For the reasons set forth above, we have considerable doubt as to the accuracy of the national and per well estimates of methane and volatile organic compounds (“VOC”)

¹ “Combustion device” and “flare” are used interchangeably and are not flares subject to 40 C.F.R. § 60.18.

emissions for hydraulically fractured oil well completions. There is significant variation in the emissions among different well types and wells from different regions. As such, a “national estimate” will not necessarily be representative of wells from a particular region (and, in fact, would be representative only by chance). As to factors that influence emissions, there are numerous factors that were not discussed in the White Papers. Most importantly, the White Papers do not adequately address the complex nature of what EPA terms “co-produced” wells, where both oil and gas are produced. Such wells are difficult to classify in terms of how any given well will behave in a wide variety of geologic formations and basins. In addition, EPA does not discuss the well-established fact that nearly all oil wells that produce appreciable amounts of gas are controlled by a combustion device for safety reasons. As mentioned above, the existing economic and safety incentives result in a majority of these wells being “controlled”—whether by a REC or combustion device. In fact, a survey submitted as part of the docket for NSPS Subpart OOOO was conducted by AXPC/ANGA member companies that showed that greater than 90% of wells were controlled prior to the rulemaking. Comment submitted by Amy Farrell, Vice President of Regulatory Affairs, America’s Natural Gas Alliance (ANGA) and Bruce Thompson, President, American Exploration and Petroleum Council (AXPC); EPA-HQ-OAR-2010-0505-4241. A similar Texas Energy Alliance survey had comparable results, again supporting the position that further EPA requirements mandating REC/flares are not necessary.²

2. *Most available information on national and per well estimates of emissions is on uncontrolled emissions. What information is available for emissions, or what methods can be used to estimate net emissions from uncontrolled emissions data, at a national and/or at a per well level?*

EPA has identified a major problem with this question—in short, there simply is not much information available on such emissions. Accordingly, IPAA and the Alliance recommend undertaking further study(ies) to ensure that EPA’s future actions are based on a reliable estimate of net emissions.

3. *Are further sources of information available on VOC or methane emissions from hydraulically fractured oil well completions beyond those described in this paper?*

² “When evaluating the section of regulations regarding ‘Green Completions’ (reduced emissions completions, or REC), the Alliance suggests that EPA in its assumptions has overestimated the potential revenue to be gained by producers from the enactment of this rule. In fact, producer actions to reduce emissions are already more the norm and not limited to the 15% of current completions which EPA uses in its economic assumptions. Thus, the positive revenue impact in the proposed regulations is overstated, as most producers are already benefiting from the procedures that the rule will mandate. The Alliance is currently surveying its membership to more accurately determine producer operations regarding reduced emissions techniques. Preliminary returns show that at least 75 % of wells drilled by Texas independents are completed to minimize emissions. This percentage will very likely be higher as the Alliance completes its surveys.” Comment submitted by Tommy Taylor, Chairmen of the Board, Texas Alliance of Energy Producers; EPA-HQ-OAR-2010-0505-4269.

As noted in the preliminary comments, there is simply not much emissions data for “hydraulically fractured oil well completions.” The White Paper touts the UT Austin study to support the notion that RECs on “co-produced oil and gas” wells achieved greater than 98% reduction. The White Paper acknowledges that “both wells” – all two of them – achieved that reduction percentage. It is not appropriate to generalize or extrapolate from data gained from gas well RECs. More focused research in this area is necessary.

4. Please comment on the various approaches to estimating completion emissions from hydraulically fractured oil wells in this paper.

a. Is it appropriate to estimate average uncontrolled oil well completion emissions by using the annual average daily gas production during the first year and multiplying that value by the duration of the average flowback period?

No. There is significant variation among wells with very different flowback characteristics. In addition, there is significant variation in the gas/oil/water mixture between flowback and the first year of production. The flow conditions in terms of volume, heat content and other critical factors change throughout the flowback period such that it is not appropriate to generate averages. Generally, the average hourly/daily gas production during the first year of production will likely be higher than during flowback because during flowback, by the very nature of the process, there is more flowback water and fewer emissions. These characteristics also vary across formations. At a minimum, the differences between different regions and formations must be accounted for, and the data does not currently exist to do that.

b. Is it appropriate to estimate average uncontrolled oil well completion emissions using “Initial Gas Production,” as reported in DI Desktop, and multiplying by the flowback period?

We question whether “Initial Gas Production” is an appropriate surrogate for “uncontrolled oil well emissions”. However, while more research is warranted, this is probably the most accurate of the four alternative options presented in the White Paper so long as it takes into consideration appropriate deration ratios to account for gas flow not being equal during the two periods. Indeed, the paper acknowledges that it estimated only three days of “Initial Gas Production” was equivalent to a seven to ten day flowback period. A better estimate would use initial production data and perform a linear regression where flowback gas at time 0.0 hrs = 0.0 gas, but again we stress that more research and data are necessary.

c. Is it appropriate to estimate average uncontrolled oil well completion emissions by increasing emissions linearly over the first nine days until the peak rate is reached (normally estimated using the production during the first month converted to a daily rate of production)?

No.

d. Is the use of a 3-day or 7-day flowback period for hydraulically fractured oil wells appropriate?

No. This data is too greatly varied. The question assumes that either a 3-day or a 7-day flowback period is appropriate – and that no other time period is appropriate. These two time periods are then use to support some preliminary cost/benefit analysis. The reality is the flowback period ranges considerably – from a few hours to a few weeks. The Subpart OOOO regulations assume a longer time period. The simple fact remains, the flowback period varies from well to well and region to region. Based on the experience of our members, EPA cannot generalize as to the length of the flowback period, especially when it comes to conducting cost/benefit analysis.

The specific nature of the questions and the lack of reliable information highlight the critical need for more research before EPA can make appropriate policy decisions relating to emissions from oil well completions.

5. Please discuss other methodologies or data sources that you believe would be appropriate for estimating hydraulically fractured oil well completion emissions.

As stated in response to previous questions, more research and data are necessary before any policy decisions should be made, given the limited amount of data presently available.

6. Please comment on the methodologies and data sources that you believe would be appropriate to estimate the rate of recompletions of hydraulically fractured oil wells. Can data on recompletions be used that does not differentiate between conventional oil wells and hydraulically fractured oil wells be reasonably used to estimate this rate? For example, in the GHG Inventory, a workover rate of 6.5% is applied to all oil wells to estimate the number of workovers in a given year, and in the ERG/ECR analysis above a rate of 0.5% is developed based on both wells with and without hydraulic fracturing. Would these rates apply to hydraulically fractured oil wells? For hydraulically fractured gas wells, the GHG Inventory uses a refracture rate of 1%. Would this rate be appropriate for hydraulically fractured oil wells?

We are not aware of any reliable method to predict the rate of recompletions. There are too many factors that can affect this rate, including, but not limited to, reserve life, oil prices, gas prices, reservoir pressure, well condition, and offset operations.

7. Please comment on the feasibility of the use of RECs or completion combustion devices during hydraulically fractured oil well completion operations. Please be specific to the types of wells where these technologies or processes are feasible. Some characteristics that should be considered in your comments are well pressure, gas content of flowback, gas to oil ratio (GOR) of the well, and access to infrastructure. If there are additional

factors, please discuss those. For example, the Colorado Oil and Gas Conservation Commission requires RECs only on “oil and gas wells where reservoir pressure, formation productivity and wellbore conditions are likely to enable the well to be capable of naturally flowing hydrocarbon gas in flammable or greater concentrations at a stabilized rate in excess of five hundred (500) MCFD to the surface against an induced surface backpressure of five hundred (500) psig or sales line pressure, whichever is greater.”

As stated in our general comments, the economic and safety incentives already exist to “control” emissions from oil well completions. Further, there are site-specific circumstances—for example, drought conditions or close proximity to structures—where flaring may not be appropriate nor safe. There also are instances where it is not technically feasible to capture or flare the gas—for example, low pressure wells, wells with low BTU content in the gas, and energized wells. A blanket requirement to conduct RECs or flaring will disproportionately affect a significant portion of low pressure, marginal wells and energized wells to the point that many will no longer be economical to operate. A “one-size-fits-all” approach simply is not appropriate.

8. *Please comment on the costs for the use of RECs or completion combustion devices to control emissions from hydraulically fractured oil well completions.*

We believe that the cost data for RECs has been borrowed from gas well operations and misapplied to oil well completions. The processes and equipment used vary considerably between gas and oil wells. The cost/benefit relationship for natural gas well RECs should not be assumed to be representative of oil well RECs. Additionally, the cost will vary considerably from well to well.

9. *Please comment on the emission reductions that RECs and completion combustion devices achieve when used to control emissions from hydraulically fractured oil well completions.*

Due to the variability of the gas mixture and the typical use of a non-engineered flare tip, the associated efficiency is unknown.

10. *Please comment on the prevalence of the use of RECs or completion combustion devices during hydraulically fractured oil well completion and recompletion operations. Are you aware of any data sources that would enable estimating the prevalence of these technologies nationally?*

The prevalence of RECs or completion combustion devices is believed to be very high because, as previously stated, at a minimum most completions use combustion devices to address safety concerns associated with venting gas.

11. *Did the EPA correctly identify all the available technologies for reducing gas emissions from hydraulically fractured oil well completions or are there others?*

We are not aware of others.

12. Please comment on estimates of associated gas emissions in this paper, and on other available information that would enable estimation of associated gas emissions from hydraulically fractured oil wells at the national- and the well-level.

We believe that any estimates of associated gas are inaccurate as a whole because of the considerable variability of reservoir characteristics.

13. Please comment on availability of pipeline infrastructure in hydraulically fractured oil formations. Do all tight oil plays (e.g., the Permian Basin and the Denver-Julesberg Basin) have a similar lack of infrastructure that results in the flaring or venting of associated gas?

No, all tight oil plays do not have a similar lack of infrastructure. It is not possible to generalize. Assuming a “similar lack of infrastructure” is too broad of a characterization. Within a basin, such as the Permian Basin or Denver-Julesberg Basin, while several wells have infrastructure, there are still wells further away from the most developed areas in these basins that do not have infrastructure. Moreover, just because a pipeline is in the “area” does not mean that infrastructure is available for an individual well or well pad. Many factors go into determining the “availability” of pipeline infrastructure. Perhaps the most influential factors are the pressure of the sales line in the area and the availability of compression. In addition to these factors, economic factors will also dictate whether a producer can tie into an existing pipeline. In addition to the aforementioned factors, local permitting decisions also play a role in determining the “availability of pipeline infrastructure.”

14. Did the EPA correctly identify all the available technologies for reducing associated gas emissions from hydraulically fractured oil wells or are there others? Please comment on the costs of these technologies when used for controlling associated gas emissions from hydraulically fractured oil wells. Please comment on the emissions reductions achieved when these technologies are used for controlling associated gas emissions from hydraulically fractured oil wells.

Although this White Paper is ostensible focused on both hydraulically fractured oil well completions and “associated gas”, the emissions related to “associated gas” are not discussed much and are not the focus of the charge questions. While the need for additional information associated with oil well RECs is noted in these comments, the paucity of data associated with “associated gas” is remarkable. Page 21 of the White Paper itself basically admits EPA does not have an accurate way to estimate the associated gas emissions. The lack of charge questions focused on associated gas is telling. The economic and safety motivations for capturing gas/emissions characterized as “associated gas” are the same as those for the rest of the E&P sector. The costs associated with reducing associated gas emissions vary considerably based on many factors. Of the various emissions “sources” identified for evaluation by the EPA, this

“source” seems to be the least understood and EPA does not have enough data to make a sound policy decision to regulate such emissions.

15. Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from hydraulically fractured oil well completions and associated gas and available options for increased product recovery and emission reductions?

We are not aware of any ongoing or planned studies.

C. Comments on Leaks from Natural Gas Production, Processing, Transmission and Storage:

1. Did this paper appropriately characterize the different studies and data sources that quantify VOC and methane emissions from leaks in the oil and natural gas sector?

When quantifying leaks from oil and natural gas facilities, it is important to have a common and rigorous definition of a leak. The leaks white paper gives the following definition:

“For the purposes of this paper, leaks are defined as VOC and methane emissions that occur at onshore facilities upstream of the natural gas distribution system.”

This definition of a leak is neither quantitative nor descriptive enough and suggests that any emission of VOCs or methane is a leak. It is critical to differentiate between leaking, venting, and normal VOC and methane emissions. Some equipment is designed to vent for safety reasons, and such emissions are not considered leaks. While the leaks white paper distinguishes between leaking and venting, the distinction becomes muddled throughout the paper. EPA says, “The definition of leak emissions in this paper was derived by reviewing the various approaches taken in the available literature.” The proliferation of many definitions of a leak in the oil and natural gas sector create a problem for rigorous analysis of leaks and the EPA should consider one clear definition of a leak.

2. Please comment on the approaches for quantifying emissions and on the emission factors used in the data sources discussed. Please comment on the national estimates of emissions and emission factors for equipment leaks presented in this paper. Please comment on the activity data used to calculate these emissions, both on the total national and regional equipment counts.

We suggest there should be more than one set of emissions factors for the entire industry. It is likely there should be one set of factors each for upstream, midstream and downstream sites based on different operating conditions, such as pressure, environmental exposure, etc. The Canadian Association of Petroleum Producers (‘CAPP’) 2007 report “[Best Management Practices: Management of Fugitive Emissions](#)”

[at Upstream Oil and Gas Facilities](#)” used different emissions factors for different types of sites to account for such differences.

3. ***Are the emission estimating procedures and leak detection methods presented here equally applicable to both oil and gas production, processing, and transmission and storage sectors?***

4. ***Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from leaks and available techniques for detecting those leaks? Please list the additional studies you are aware of.***

We are aware of three ongoing studies of leaks in the oil or natural gas sector:

- Center for Alternative Fuels, Engines and Emissions, University of West Virginia
- Penn State University
- Scott Institute for Energy Innovation, Carnegie Mellon University

5. ***Are there types of wells sites, gathering and boosting stations, processing plants, and transmission and storage stations that are more prone to leaks than others? Some factors that could affect the potential for leaks are the number and types of equipment, the maintenance of that equipment, and the age of the equipment, as well as factors that relate to the local geology. Please discuss these factors and others that you believe to be important.***

The paper lists potential sources of leaks, which includes nearly every type of component found at oil and natural gas sites but only lists gas driven pneumatic pumps as an example of equipment that vents. We suggest this is confusing to the reader and oversimplifies the difference between leaks and vents. A given piece of equipment has the potential to both leak and vent depending on its design and intended service.

6. ***Did this paper capture the full range of technologies available to identify leaks at oil and natural gas facilities?***

No, there are other technologies and methods that can be used to detect leaks. Companies routinely use audio, visual and olfactory surveys to locate any leaks and repair them. This is perhaps the lowest technological method, but it has been successfully used for many decades.

There are also several other detection methods, each with its own advantages and costs. We are aware of four instrument companies that use tunable diode laser absorption spectroscopy to detect gas emissions. Two instrument companies use light detection and ranging systems. Several academic groups and some instrument companies use cavity ring-down spectroscopy. Finally, we are aware of one system that uses a pulsed infrared laser.

7. ***Please comment on the pros and cons of the different leak detection technologies. Please discuss efficacy, cost and feasibility for various applications.***

Many new regulations and studies are focused on infrared (IR) cameras for use in leak detection. IR cameras should be thought of as one possible tool in a list of several technologies used to reduce leak emissions in LDAR programs. For example, the Carbon Limits report from 2013 only analyzes leak detection with infrared (IR) cameras, and it does not appear to take into account any leak detection prior to an IR camera program, therefore overestimating the benefits. Any cost evaluation of a new detection technology must not assume that no leak detection is currently taking place.

8. ***Please comment on the prevalence of the use of the different leak detection technologies at oil and gas facilities. Which technologies are the most commonly used? Does the type of facility (e.g., well site versus gathering and boosting station) affect which leak detection technology is used?***

EPA would need to conduct a survey of industry to fully answer this question, especially with respect to the prevalence of various technologies. The type of facility and the conditions during measurement do affect which technology would be best. For example, IR cameras cannot “see” very small emissions, and they do not work well in windy conditions or extreme cold. Other technologies will have detection limits, as well and will not be suitable for every type of emission.

9. ***Please provide information on current frequencies of revisit of existing voluntary leak detection programs in industry and how the costs and emission reductions achieved vary with different frequencies of revisit.***

The frequency of LDAR surveys can have a large impact on the cost of an LDAR program. The CAPP 2007 report “[Best Management Practices: Management of Fugitive Emissions at Upstream Oil and Gas Facilities](#)” found that annual monitoring will produce a 75% reduction in fugitive emissions. They also found different frequencies were most appropriate for different types of oil and gas sites, 1-3 years for exploration and production sites, quarterly or bi-annually for gas processing or compressor sites.

Many of the recently proposed state rules for LDAR require quarterly or even monthly survey frequencies, which add considerable cost to the companies. The CAPP report and a Clearstone Engineering Ltd. technical report from January 2014, “[Update of Fugitive Emissions at Upstream Oil and Gas Facilities](#),” found the vast majority of leaks are found and repaired during the first inspection, while subsequent inspections only find a small number of leaks. This finding has important implications for cost/benefit analyses of LDAR programs. Continued monthly or quarterly LDAR surveys will rapidly lose their benefits with each subsequent survey while the costs remain the same.

10. ***Please comment on the potential for using ambient/mobile monitoring technologies in conjunction with OGI technology. This would be a two-phase approach where the***

ambient/mobile monitoring technology is used to detect the presence of a leak and the OGI technology is used to identify the leaking component. Please discuss efficacy, cost and feasibility.

Mobile technology can be used in the field and can be a more efficient method of detecting leaks than currently prescribed methods. These systems can be expensive to obtain and to operate, so the cost effectiveness must be evaluated.

11. Please comment on the cost of detecting a leak when compared to the cost to repair a leak. Multiple studies described in this paper suggest that detecting leaks is far more costly than repairing leaks and, due to generally low costs of repair and the subsequent product recovery, it is almost always economical to repair leaks once they are found. Please comment on this overall conclusion.

Please see our answer to question 12.

12. If the conclusion is correct that it is almost always economical to repair leaks once they are found, then how important is the quantification of emissions from leaks when implementing a program to detect and repair leaks?

EPA's Charge Question 11 asks about the cost effectiveness LDAR programs, and Charge Question 12 asks about the importance of quantifying emissions of leaks. We are answering these two questions together because they are intrinsically linked and it is not possible to calculate the cost effectiveness of LDAR programs without quantifying emissions. Claims have been made that it is "almost always economical to repair leaks", but it is impossible to know the economics of repairing a leak if the amount of VOC or methane emitted is unknown.

Quantification of leaks is not easy and takes considerable instrumentation, training in atmospheric and electromagnetic radiation sciences, and engineering knowledge of oil and natural gas equipment. Perhaps due to these requirements there is a paucity of original data on leaks from oil and natural gas equipment. We suggest EPA consider the CAPP 2007 report "[Best Management Practices: Management of Fugitive Emissions at Upstream Oil and Gas Facilities.](#)" CAPP has collected emissions data on over 275,000 components and developed efficient LDAR programs.

Most currently used leak measurement methods are qualitative, rather than quantitative, making them almost useless for the purpose of cost benefit analysis LDAR programs. One such measurement that has become popular is through the use of infrared ("IR") cameras. The use of one IR camera aimed at an oil or natural gas facility can indicate a leak when it is used by a properly trained person, but it cannot give a quantitative measure of the amount leaking.

Many of the recent cost benefit studies for LDAR programs do not include costs to industry in addition to purchasing or leasing the detection technology, or they vastly underestimate human resource and other costs. An analysis from one member company

of field work, travel and reporting time for a typical LDAR program found that 550 new LDAR positions would be needed nationwide. There are currently 80-100 LDAR contractors. Most studies also do not take into account costs such as repairs resulting from false positive leak detection, IR camera repair, IR camera training time and data management of the thousands of images produced.

13. Please comment on the state of innovation in leak detection technologies. Are there new technologies under development that are not discussed in this paper? Are there significant advancements being made in the technologies that are not described in this paper?

We are not aware of new technologies at this time, but are aware of how far leak detection technology has come in recent years. There should always be an expectation that new technology will be developed and any EPA recommendations should provide flexibility to adapt to this evolving technology.

D. Comments on Liquids Unloading Processes:

Before addressing the charge questions, we would like to make a few overarching comments that summarize our position related to liquids unloading. EPA has identified the liquids unloading process as a potential source of emissions. This is not news to the industry. The industry has a strong economic incentive to minimize venting episodes. Indeed, what EPA views as a pollutant is generally viewed by industry as a salable product and thus industry has an economic incentive to capture as much of the gas as possible. Unfortunately, it is not always possible to unload without venting—sometimes for safety reasons and sometimes for technological reasons. The limitations on the ability to minimize venting are difficult to predict and largely well-specific.

Although the challenges associated with liquids unloading are equally prevalent among horizontal and vertical wells, the ability to recover the cost of “controls” will most likely disproportionately affect smaller operators, marginal wells and vertical wells. Nowhere in the charge questions or White Paper does EPA attempt to address the potential for such disproportionate economic impacts to result from a “one size fits all” approach to minimizing emissions during liquids unloading. The need to unload liquids depends primarily on reservoir pressure, liquid/gas ratio, and surface operating pressure; the most appropriate technology used to unload will depend on the producing formation, site equipment and logistics, and other considerations. There is a wide variety of reservoir properties across and within basins, and flexibility is critical in the continued production of these wells.

1. Please comment on the national estimates of methane emissions and methane emission factors for liquids unloading presented in this paper. Please comment on regional variability and the factors that influence regional differences in VOC and methane emissions from liquids unloading. What factors influence frequency and duration of liquids unloading (e.g., regional geology)?

As a general matter, the national estimates of methane emissions based on EPA's Greenhouse Gas Reporting are overstated, over-reported and dated at this point. The 2012 API/ANGA study included in the White Paper indicates as much and concludes that EPA's Greenhouse Gas Inventory was overestimated by orders of magnitude. More source specific data—i.e., data specifically focused on liquids unloading—is needed before conclusions should be drawn as to this subsector's contribution to methane emissions from the broader oil and natural gas sector.

The formulas used by EPA to calculate the gas volumes vented during unloading events estimates that the entire well column is vented during an event. The reason for the unload is because fluid is sitting in this column, taking up this space, and resulting in an overestimation of emissions. Additionally, the formulas utilize only a casing diameter for wells without plunger lifts (and tubing diameter for wells with a lift). Most wells are generally equipped with production tubing strings in an effort to increase the velocity of the gas and liquids and reduce the potential for liquid loading problems. When these tubing strings are in place, gas volumes vented during unloading events would be from the casing-tubing annulus (area between the outside of the tubing and the inside of the well's casing) and not from the entire volume of the well's casing. This is not accounted for in many of the estimates.

In addition, the formulas used by EPA assume that gas is being vented for any well liquid unload lasting longer than one hour (or 30 minutes for unloads that are plunger lift assisted). During the liquid unloading process, there is usually an initial release of gas followed by a period of time where operators are waiting for the liquid to travel up the well bore and nothing is being released from the well; this can for only a few minutes and up to several hours. The formulas assume that any duration longer than one hour is continually venting at a rate equal to the production rate of gas when in fact no gas is being vented, significantly overestimating the emissions from these activities.

Factors influencing regional differences in VOC and methane emissions are a complex set of variables that include temperature, pressure, hydrocarbon composition of the oil and gas within the production formation, gas to liquid ratio, well configuration, well depth and surface conditions at the time of the unloading event. The factors that influence the frequency and duration of liquids unloading include those listed in the previous sentence, and the solution for each well and/or application is based on engineering calculations and judgment and is intrinsically well-specific. Production engineers run models to determine the proper design and operating parameters. The numerous factors and inability to generalize even by formation make it difficult to predict which wells will be more susceptible to high levels of emissions associated with liquids unloading.

- 2. Is there further information available on VOC or methane emissions from the various liquids unloading practices and technologies described in this paper?***

We are not aware of additional final reports at this point, but the industry continues to explore ways to address liquids unloading in the most cost-efficient and environmentally cognizant manner.

3. ***Please comment on the types of wells that have the highest tendency to develop liquids loading. It is EPA's understanding that liquids' loading becomes more likely as wells age and well pressure declines. Is this only a problem for wells further down their decline curve or can wells develop liquids loading problems relatively quickly under certain situations? Are certain wells (or wells in certain basins) more prone to developing liquids loading problems, such as hydraulically fractured wells versus conventional wells or horizontal wells versus vertical wells?***

The need for liquids unloading is not based on a strict set of parameters or rules. It is based on a complex set of variables—primarily reservoir pressure, but also including (but not limited to) gas to oil ratio, geologic formation types, and age of well. In addition to geological factors, technology-based factors include (a) large or no production tubing strings installed, (b) wells with high sales line pressure and no compression equipment installed at the surface, and (c) wells not equipped with artificial lift equipment such as gas lift mandrels/valves, plunger lift, rod pump, etc. Regarding the type of well, horizontal or hydraulically fractured wells are no more likely than vertical or non-hydraulically fractured wells to develop liquids loading problems. It is not only a problem for wells further down their decline curve.

Simply put, one cannot generalize—there is no particular pattern or predictable model that would forecast which well types are prone to having liquids loading problems. It is the inability to generalize that makes each well unique and requires a case-by-case analysis to address a liquid loading problem. That said, there are some trends—the highest tendency are deeper wells with high liquid to gas ratios and low bottom hole pressure. Because the reservoir pressure does decline over time, liquid loadings are more prevalent in older wells. Wells drilled and completed in formations drained by previous production may experience loading problems more quickly. All wells with liquid saturations above irreducible levels will develop liquid loading conditions.

4. ***Did this paper capture the full range of feasible liquids unloading technologies and their associated emissions? Please comment on the costs of these technologies. Please comment on the emission reductions achieved by these technologies. How does the well's life cycle affect the applicability of these technologies?***

The list provided by EPA covers the most common liquids unloading technologies but is not complete (e.g., vacuum operations gas lifts, and electric submersible pumps). During the typical life cycle of a gas well, it is our industry's accepted practice to firstly produce the well naturally (unassisted by artificial lift equipment) until technical or economic factors warrant installation of additional equipment. After that point, various practices are employed, including but not limited to compression, plunger lift, gas lift, rod pump, soap sticks, velocity string installation, and capillary injection of surfactants. Not all of these options are technically feasible and will

depend on the specific conditions of the well. The well's life cycle is extended by using any one or a combination of these technologies. Attached to these comments are some of the advantages and disadvantages of plunger lifts and sucker rod pumps from the perspective of Pioneer Natural Resources. The cost of the technologies varies and what will constitute a cost-effective technology will vary from well to well. For example with plunger lifts, the capital, installation, and startup cost is an exponential costing issue based on ever increasing depth of the well (e.g., the cost of a 11,000 to 12,000 foot well might approximate \$25,000 to \$30,000 for certain operations in East Texas whereas a 1000 foot well may only be \$2000 or \$3000). Also related to plunger lifts, a "smart technology" cost is dependent on many variables such as well density and availability of a communication network. The communication network for 400 densely spaced wells can easily cost approximately \$4 million dollars (average of \$10,000/well before adding the cost of the smart controls themselves). The EPA's high range of \$18,000/well is not necessarily "high" for many situations. As to artificial lifts, the costs are substantially more. One member indicated capital and installation costs for 11,000 -12,000 foot wells are in the range of \$150,000 per well -- much higher than EPA's estimates. Again, the depth of the well influences the costs figures and it is difficult and inappropriate to generalize. The best solution to the liquids unloading problem is a case-by-case decision based on the engineering judgment of the operators. The well's life cycle has the effect that has been described in this paper and in Charge Question No. 3.

5. *Please provide any data or information you are aware of regarding the prevalence of these technologies in the field.*

Although not necessarily representing the latest technologies, the following sources can serve as decent reference books on artificial lifts:

- Brown, K.E., Technology of Artificial Lift, Vols. 2a & 2b, Penwell, Tulsa 1980
- Fleshman, R. and Lekic, H.O., Artificial Lift for High-Volume Production, Oilfield Review, Spring 1999
- Gibbs, S.G., Rod Pumping, Sam Gibbs, Midland, Texas 2012.

The prevalence of these technologies in the field will be driven by economics—a driving force that not only benefits industry but also the environment. A concept that seems to be unrecognized in this and the other White Papers is that the driver for development of these technologies is to keep the well producing as long as economically feasible. Inherent in evaluating what is economically feasible is selecting those technologies that require the least amount of investment (capital, operation and maintenance, cost of energy) and greatest return. The development of new technologies is not stagnant, and to conclude that the White Paper captures an accurate snap-shot in time of the prevalent technologies inappropriately implies that technologies are not constantly evolving.

6. *In general, please comment on the ability of plunger lift systems to perform liquids unloading without any air emissions. Are there situations where plunger lifts have to*

vented to the atmosphere? Are these instances only due to operator error and malfunction or are there operational situations where it is necessary in order for the plunger lift to effectively remove the liquid buildup from the well tubing?

Plunger lift systems in many cases allow the well to continue to produce through the production processes such that there are no more emissions than those expected from a fully functioning well and production battery. In most cases, the produced gas is not vented to the atmosphere when the plunger cycles to the surface, but rather is diverted to a gas sales line and never enters the atmosphere. However, to simply characterize plunger lift systems as “emission free” is inaccurate, and in many situations the operation of the lift will result in less emissions. There are cases where a plunger lift may vent to the atmosphere because the well stream pressure is below the operating pressure of the process equipment, thus necessitating the release of emissions in the normal operating procedures. These releases are not due to operator error or malfunction the vast majority of the time, but rather result from operational situations. Plunger lifts are often utilized because they are a cost-effective means of extending the life of a well, but they are not a panacea that should be forced on industry as a “one size fits all” solution. There is not a single fix for liquids unloading, despite the apparent preference in the White Paper for plunger lifts.

- 7. Based on anecdotal experience provided by industry and vendors, the blowdown of a well removes about 15% of the liquid, while a plunger lift removes up to 100% (BP, 2006). Please discuss the efficacy of plunger lifts at removing liquids from wells and the conditions that may limit the efficacy.***

We believe this anecdotal information is inaccurate. The percent liquids removal during blowdowns for unloading purposes is too low. Common sense dictates that if blowdowns resulted in only 15% removal, blowdowns would be occurring much more frequently. Conversely, to say that something can remove 100% of the liquid is an exaggeration. At optimal operation, it is very rare for a plunger lift to remove 100% of the liquid. It is difficult to generalize what factors impact the efficacy of plunger lifts as they are used over a broad range of conditions. Due to the nature of how plungers are designed and constructed and the heterogeneity of the inside of the tubing string, there will always be liquid slippage that reduces the efficiency of the plunger as it travels to the surface.

- 8. Please comment on the pros and cons of installing a plunger lift system during initial well construction versus later in the well's life. Are there cost savings associated with installing the plunger lift system during initial well construction?***

This charge question suggests a fundamental lack of understanding of the use of plunger lift systems. We are unaware of any plunger lift being installed during the initial well construction as it will not be needed for several months, if not years. Installing equipment in a well that is not being used does not make good engineering sense from both a well production and equipment perspective. Unnecessary obstructions in a well bore present potential operational concerns and it is impractical to store unused

equipment in a well over a long period of time. A straight up comparison of the cost of installing a plunger lift during initial construction with the cost of installation at the time it is needed may indicate that installation is less expensive at initial construction, but that is not the end of the analysis. The mere passage of time likely will make the cost of equipment more expensive. Additionally, whether the equipment installed during initial well construction would be functional or appropriate for the configuration of the well 10 to 20 years later is highly suspect—likely requiring the equipment to be retrofitted and customized at the time it is needed. It’s a nonsensical comparison.

9. *Please comment on the pros and cons of installing a “smart” automation system as part of a plunger lift system. Do these technologies, in combination with customized control software, improve performance and reduce emissions?*

EPA needs to be clear by what it means by the term “‘smart’ automation.” There are certain systems that are automated—e.g., their operation is triggered based on set parameters (certain time and/or pressure that trigger operation)—and then there are automation systems that are truly “smart” in that they “learn” to optimize operation based on the unique characteristics of a particular well. Smart automation systems are not feasible at certain locations as they require instrumentation, network access and a reliable electric source and depend on the complexity of the production profile, well type, and physical location of the well. On the other hand, some plunger wells have acceptable results with less technology. It is difficult to generalize. As with most of the technologies associated with liquids unloading, where it is economical and feasible to install the technology, operators are already utilizing automation and smart technologies. Smart automation will not be feasible in all situations.

10. *Please comment on the feasibility of the use of artificial lift systems during liquids unloading operations. Please be specific to the types of wells where artificial lift systems are feasible, as well as what situations or well characteristics discourage the use of artificial lift systems. Are there standard criteria that apply?*

As noted above, the feasibility of the use of artificial lift systems is generally site-specific and therefore it is difficult to generalize. Artificial lift systems are just one of the available “tools” or technologies to extend the useful life of a well and are utilized where cost-effective. That said, they tend to be cost-prohibitive on deeper low production gas wells and work best on shallow wells capable of setting a pump/plunger/gas lift below the bottom perforations. Some characteristics that discourage the use of artificial lift include deep formations, corrosive production fluids, wells with high scaling tendency, and deviated wellbores. Please refer to the attachments referenced above from Pioneer Natural Resources that discuss the advantages and disadvantages of sucker rod pumps and plunger lifts. The feasibility of artificial lifts must be assessed according to the conditions of the individual well. One size does not fit all.

11. *The EPA is aware that in areas where the produced gas has a high H2S concentration combustion devices/flares are used during liquids unloading operations to control vented emissions as a safety precaution. However, the EPA is not aware of any*

instances where combustion devices/flares are used during liquids unloading operations to reduce VOC or methane emissions. Please comment on the feasibility of the use of combustion devices/flares during liquids unloading operations. Please be specific to the types of wells where combustion devices/flares are feasible. Are there operational or technical situations where combustion devices/flares could not be used?

In certain situations, gas wells with liquid content that are unloaded are capable of being controlled with flares attached to the tank vents at the production battery. In others, the high pressures in certain regions make routing blowdowns to tanks tanks and flares extremely unsafe. Even wells that are blown down can sometimes be vented through tanks that are controlled in many cases by flares. The capability to do this, however, depends greatly on the conditions of the well bore and the equipment used to control (tanks, flares, etc.) These flares and the associated tanks/tank vents are not specifically designed to accommodate liquids unloading. Regarding the use of flares specifically for liquids unloading events, there are several design and operational issues: (1) liquids unloading are slug flow events that are inconsistent in both gas volumes and quality, (2) consequently, designing a flare for the wide range of operating conditions is challenging, (3) additional equipment may be required to prevent liquids from reaching the flare (separators, etc.), and (4) the intermittent nature of these events is another challenging design condition especially in avoiding smoking conditions, etc. To the extent that EPA contemplates a continuous flare to minimize emissions from these intermittent events, the negative externalities associated with the carbon dioxide emissions from the pilot should be factored into any analysis. To accommodate the operational issues associated with flares and associated equipment designed to specifically address liquids unloading, they would need to be relatively large which could present safety hazards and create local permitting issues.

12. Given that liquids unloading may only be required intermittently at many wells, is the use of a mobile combustion device/flare feasible and potentially less costly than a permanent combustion device/flare?

The use of a mobile combustion device/flare will vary from well to well and a generalization cannot be made. Each type of combustion device/flare has certain pros and cons that need to be evaluated in the context of the operating characteristics of a particular well. In addition, many cases will warrant additional equipment than just the flare (separators), which factor into the technical feasibility and cost. Portable flares are a logistical concern (e.g., permitting considerations) and permanent flares are challenging as described in the answer to Charge Question No. 11.

13. Given that there are multiple technologies, including plunger lifts, downhole pumps and velocity tubing that are more effective at removing liquids from the well tubing than blowdowns, why do owners and operators of wells choose to perform blowdowns instead of employing one of these technologies? Are there technical reasons other than cost that preclude the use of these technologies at certain wells?

The question implies that operators simply default to blowdowns because it is the lowest-cost option. This implication is inaccurate. The ability to blowdown, in and of itself, or in conjunction with other technologies/procedures such as plunger lifts, is just one of the technologies/procedures to extend the economic life of a well. In addition, none of these technologies are perfect; each of them may encounter reasons to blowdown or unload the well that could not be avoided. Some of the possible technical constraints include but are not limited to endangered species concerns, noise, local restrictions, and power source availability.

14. Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from liquids unloading events and available options for increased product recovery and emissions reductions? The EPA is aware of an additional stage of the Allen et al. study to be completed in partnership with the EDF and other partners that will directly meter the emissions from liquids unloading events. However, the EPA is not aware of any other ongoing or planned studies addressing this source of emissions.

The second stage of the Allen et al. study is the most prominent study of which we are aware. The question introduces a subjective element that may not be necessary or helpful in that it asks for studies that will “substantially improve” the understanding of emissions associated with liquids unloading. The industry is continually evaluating technologies and procedures to extend the economic life of wells and inherent in that evaluation and development of technologies is a desire to minimize “emissions” which for the most part a saleable product that industry would prefer to capture versus vent to the atmosphere.

E. Comments on Pneumatics:

1. Did this paper appropriately characterize the different studies and data sources that quantify emissions from pneumatic controllers and pneumatic pumps in the oil and gas sector?

Much of the data referenced by EPA in this white paper is relatively old, and many of the listed studies do not generate new, independent emissions calculations but reference the Gas Research Institute/EPA report from 1996. Industry was reliant on so called high bleed devices at that time, which is neither representative of current practice nor commonly available devices.

EPA’s recent NSPS OOOO regulations require the installation of low-bleed pneumatic controllers at new and modified sites. We suggest the proliferation of low-bleed devices as a result of this rule will provide a new source of data on emissions from gas driven pneumatic controllers and encourage EPA to consider the effects of this rule on both methane and VOC emissions.

- 2. Please discuss explanations for the wide range of emission rates that have been observed in direct measurement studies of pneumatic controller emissions (e.g., Allen et al., 2013 and Prasino 2013). Are these differences driven purely by the design of the monitored controllers or are there operational characteristics, such as supply pressure, that play a crucial role in determining emissions?**

We do not have an explanation for this at this time.

- 3. Did this paper capture the full range of technologies available to reduce emissions from pneumatic controllers and pneumatic pumps oil and gas facilities?**

This paper discusses several alternatives to gas driven pneumatics, including instrument air, mechanical and solar powered systems for controllers, and instrument air, solar direct current and electrical systems for pumps. The use of these technologies depends on the characteristics of the oil or natural gas site in question, and industry needs to retain the flexibility to use many types of technology.

- 4. Please comment on the pros and cons of the different emission reduction technologies. Please discuss efficacy, cost and feasibility for both new and existing pneumatics.**

There is generally a higher cost benefit ratio for replacing existing pneumatics than for installing low bleed devices at new sites.

- 5. Please comment on the prevalence of the different emission control technologies and the different types of pneumatics in the field. What particular activities require high bleed pneumatic controllers and how prevalent are they in the field?**

Even before the promulgation of NSPS OOOO, several of our member companies were installing low bleed devices, including controllers and pumps, and thus emissions from pneumatic devices has been falling for the past several years. Evidence of this was reported in Allen and others (2013), which found emissions from pneumatic devices, were significantly lower than those reported in EPA's Greenhouse Gas Inventory, which relies on the Gas Research Institute/EPA measurements from 1996.

Low bleed pneumatic devices do not always operate well at wet gas sites, as they can clog. To our knowledge, this is not a widespread problem, but industry does need the flexibility to use high bleed pneumatics in a few cases.

- 6. What are the barriers to installing instrument air systems for converting natural gas-driven pneumatic pumps and pneumatic controllers to air-driven pumps and controllers?**

Whether or not a site has access to electricity is a major factor in determining the type of pneumatic devices used. Air driven, mechanical and electric pump systems all require access to electricity, but this access can be rare in remote areas. Electrification of a remote field is often not feasible given endangered species considerations, the difficulty

in gaining rights of way for transmission, and cost. The alternative would be the inclusion of a gas fired generator on site, which may have more NOx and CO emissions than those emitted by low bleed pneumatics. There is also some question as to the overall emissions reductions if the electricity is generated from a coal-fired power plant.

7. Are there situations where it may be infeasible to use air driven pumps and controllers in place of natural gas-driven pumps and controllers even where it is feasible to install an instrument air system?

The reliability of the electric power must be taken into consideration. It is critical that pneumatic controllers operate, and unreliable electric power can be an issue in remote areas that are electrified. Companies will often choose to install natural gas driven pneumatics in an area with access to electricity for reliability reasons.

8. Did this paper correctly characterize the limitations of electric-powered pneumatic controllers and pneumatic pumps? Are these electric devices applicable to a broader range of the oil and gas sector than this paper suggests?

Solar can be and often is used to operate pneumatics in remote areas, however solar and electric systems are not as reliable as natural gas-driven pneumatics and cannot be used universally. It is critical to our members' operations that pneumatic controllers operate reliably for safety and well production reasons and to reduce environmental impacts.

9. Are there ongoing or planned studies that will substantially improve the current understanding of VOC and methane emissions from pneumatic controllers and pneumatic pumps and available techniques for increased product recovery and emissions reductions?

The University of Texas/EDF partnership is currently studying emissions from pneumatic devices.

In addition to the comments provided above, IPAA and the Alliance endorse the comments of AXPC and ANGA. We appreciate the opportunity to provide comments on the White Papers and would be happy to have further discussion with the agency regarding the issues raised above. Please contact me or Matt Kellogg at 202.857.4722, Ursula Rick at 303.623.0987, or Jim Elliott at 202.361.8215 if you have any questions regarding these comments.

Sincerely,

A handwritten signature in black ink that reads "Lee O. Fuller". The signature is written in a cursive style with a large, looping initial "L".

Lee O. Fuller
Vice President of Government Relations
Independent Petroleum Association of America

A handwritten signature in black ink that reads "Kathleen Sgamma". The signature is written in a cursive style with a large, looping initial "K".

Kathleen Sgamma
Vice President of Government & Public Affairs
Western Energy Alliance

Plunger Lift

Advantages & Disadvantages

Advantages	Disadvantages
<p>Capital cost is very low if the well supplies adequate lift gas (no compressor required).</p> <p>Operating cost is usually very low. There is no fuel cost inasmuch as the well supplies lifting energy.</p> <p>Hot oiling the tubing to remove paraffin is not necessary because of plunger cycling</p> <p>It is usually possible to produce the well very nearly to depletion.</p> <p>Virtually the entire plunger-lift system can be moved to a different well without a pulling unit. Salvage value is therefore high.</p> <p>The system can be automated with smart controllers which adjust shut-in time (waiting for casing pressure to rise) in order to optimize liquid handling capacity.</p> <p>The system is unobtrusive and quiet.</p>	<p>Plunger sticking can be a major problem. This is usually caused by sand or scale.</p> <p>The system requires tweaking and adjusting to react to productivity changes. Operator training is vital.</p> <p>The system does not perform well if a packer is installed. The packer diminishes the energy-storing capacity of gas in the casing.</p> <p>Sometimes measurement of gas is imprecise because gas flow can outrun the meter.</p>

▪ Plunger Lift Advantages

- Helpful in dewatering gas wells
- No rig required for installation
- Easy maintenance
- Handles gas
- Good in deviated wells
- Allows wells to lift liquid slugs under using their own energy
- Plunger lift installation for a flowing well is nominal in cost when compared to other methods
- Plunger installations in existing gas lift wells may help fluid fall back and increase volumetric efficiency

■ Plunger Lift Disadvantages

- Low volume production (many installations lift < 5 BPD).
- Usually plungers are used only as a temporary means to maintain production until another method of lift is chosen and installed.
- Plunger action will cause surging of gas and liquids at the separator facility, so these potential surges must be considered.
- Since plunger lift is more of a mechanical process than gas lift, operating personnel must spend proportionately more time.
- Requires constant surveillance so that minor mechanical or production problems are discovered and acted on before they develop into major problems.
- Solids may stick the plunger which will result in loss of production.

Sucker Rod Pump

Advantages & Disadvantages

Advantages	Disadvantages
<p>Design and diagnostic methods are mature and accurate.</p> <p>System can be adjusted to changing conditions in the reservoir such as production rate.</p> <p>The method can draw producing pressure down to a low value. It is capable of depleting the well to low reservoir pressures.</p> <p>Equipment is available in variety of sizes.</p> <p>Surface units have good resale value and can be moved to other locations. Units last for decades if properly used and maintained.</p> <p>System is applicable to multiple completions and slim holes but with some problems.</p> <p>It is usually a vented system wherein the casing annulus is available for chemical treatments, fluid level measurements, and venting of gas for efficiency reasons.</p> <p>If electrified, the system can be automated with pump-off controls and time clocks.</p> <p>High salvage value</p>	<p>Deviated wells cause additional rod friction which can lead to tubing leaks and rod failures.</p> <p>Produced solids are troublesome and can cause downhole pumps to stick and fail.</p> <p>Free gas entering the pump can severely decrease pump efficiency.</p> <p>Because of rod reciprocation, tubing cannot be effectively internally coated for corrosion protection.</p> <p>Rods and tubing are prone to paraffin deposition problems which require hot-oil treatments.</p> <p>Method is limited to relatively low volumes in deep wells. Production can also be limited by rod-fall problems in shallow wells.</p> <p>Surface equipment may be unsightly and obtrusive in some urban locations. In addition, surface equipment can inhibit farming and irrigation activities.</p> <p>System is heavy and bulky for offshore-platform application.</p>

- **Sucker Rod Pump Advantages**
 - Most field and operating personnel are familiar with sucker rod type lift, the installation and operation is not complicated.

 - Design, analysis, optimization, and surveillance are developed and mature for this lift system.

- **Sucker Rod Pump Disadvantages**
 - Volume limitations are due to tubing size and seating nipple depth.
 - Volumetric efficiency is reduced in wells with high GOR, if solids are produced, if paraffin forms, or if the fluid is sour or corrosive.
 - Deviated wells can pose a problem if care is not taken in designing the wellbore path.
 - Improper sucker rod handling on the surface and make-up techniques can cause many failures.