August 2, 2016

By Electronic Submission

EPA Docket
Center (EPA/DC), Environmental
Protection Agency, Mail Code 28221T,
1200 Pennsylvania Ave. NW.
Washington, DC 20460

Proposed Information Collection Request; Comment Request; Information Collection Effort for Oil and Gas Facilities [EPA–HQ–OAR–2016–0204; FRL–9946–70–OAR]

These comments are filed on behalf of the Independent Petroleum Association of America (IPAA) and the American Exploration and Production Council (AXPC) (collectively, IPAA/AXPC).

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 the U.S. Environmental Protection Agency (EPA) policy decisions to regulate methane directly from the oil and natural gas sector. Independent producers develop about 95 percent of American oil and natural gas wells, produce 54 percent of American oil, and produce 85 percent of American 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.

AXPC is a national trade association representing 30 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 production of oil and natural gas. Moreover, our 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 innovative and advanced technologies necessary to explore for and produce oil and natural gas, both offshore and onshore, from non-conventional sources.

Additionally, they are joined by the American Association of Professional Landmen (AAPL), the Association of Energy Service Companies (AESC), the International Association of Drilling Contractors (IADC), the International Association of Geophysical Contractors (IAGC), the National Stripper Well Association (NSWA), the Petroleum Equipment & Services Association (PESA), and the following organizations:

Arkansas Independent Producers and Royalty Owners Association
California Independent Petroleum Association
Coalbed Methane Association of Alabama
Colorado Oil & Gas Association
East Texas Producers & Royalty Owners Association
Eastern Kansas Oil & Gas Association
Florida Independent Petroleum Association
Idaho Petroleum Council
Illinois Oil & Gas Association
Independent Oil & Gas Association of New York
Independent Oil & Gas Association of West Virginia
Independent Oil Producers' Agency
Independent Oil Producers Association Tri-State
Independent Petroleum Association of New Mexico
Indiana Oil & Gas Association
Kansas Independent Oil & Gas Association
Kentucky Oil & Gas Association
Louisiana Oil & Gas Association
Michigan Oil & Gas Association
Mississippi Independent Producers & Royalty Association
Montana Petroleum Association
National Association of Royalty Owners
New Mexico Oil & Gas Association
New York State Oil Producers Association
North Dakota Petroleum Council
Northern Montana Oil and Gas Association
Ohio Oil & Gas Association
Oklahoma Independent Petroleum Association
Panhandle Producers & Royalty Owners Association
Pennsylvania Independent Oil & Gas Association
Permian Basin Petroleum Association
Petroleum Association of Wyoming
Southeastern Ohio Oil & Gas Association
Tennessee Oil & Gas Association
Texas Alliance of Energy Producers
Texas Oil and Gas Association
Texas Independent Producers and Royalty Owners Association
Utah Petroleum Association
Virginia Oil and Gas Association
West Slope Colorado Oil & Gas Association
West Virginia Oil and Natural Gas Association

Collectively, these groups represent the thousands of independent oil and natural gas explorers and producers, as well as the service and supply industries that support their efforts that will be most significantly affected by the actions resulting from these regulatory proposals. In addition to the specific comments made herein, we support those comments submitted separately by the participants in these comments. IPAA/AXPC also endorses and supports the comments of the

Western Energy Alliance (WEA) and the American Petroleum Institute (API) submitted on the proposed ICR referenced above.

General Comments

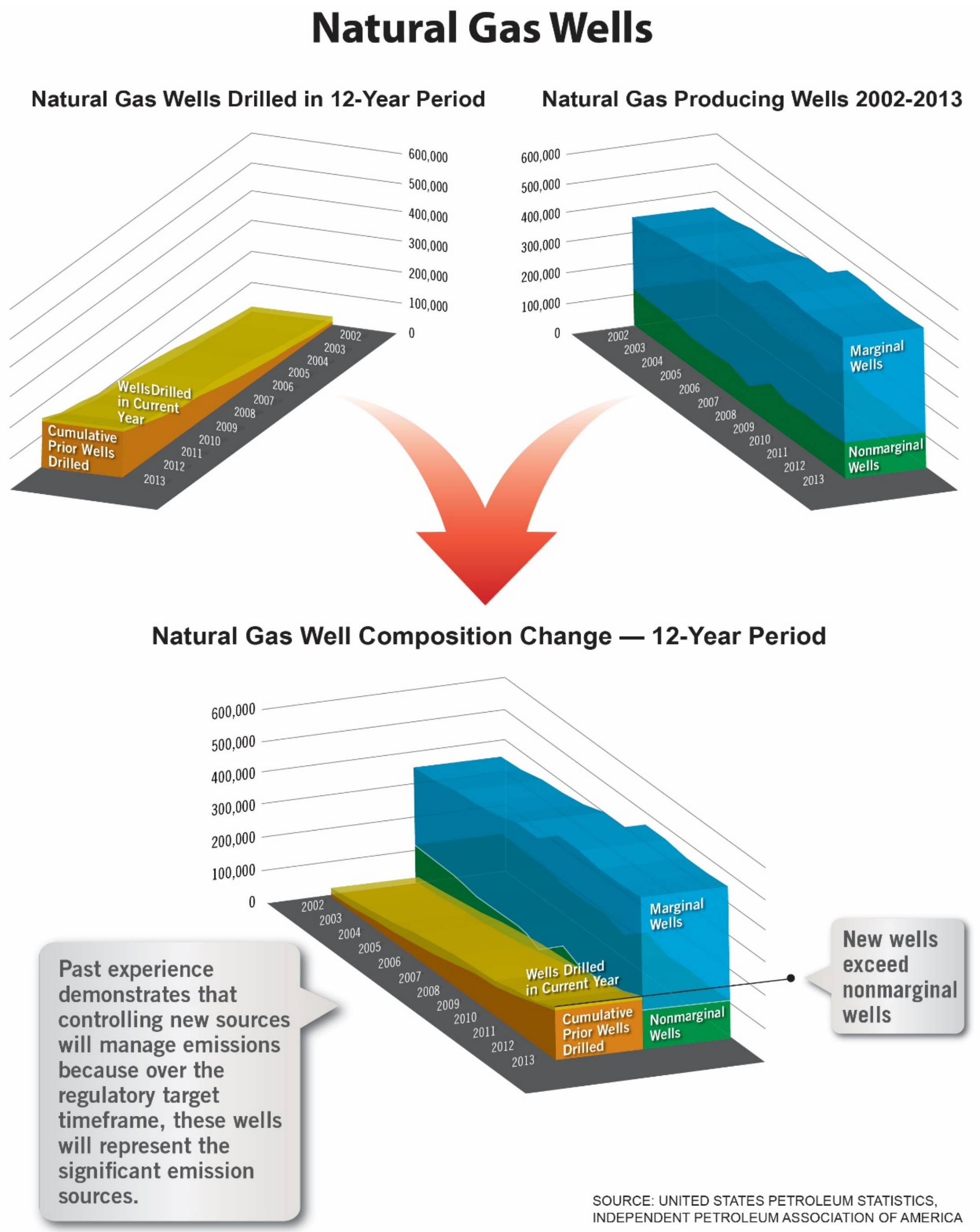
EPA Needs to Improve Its Understanding of the Oil and Natural Gas Production Industry

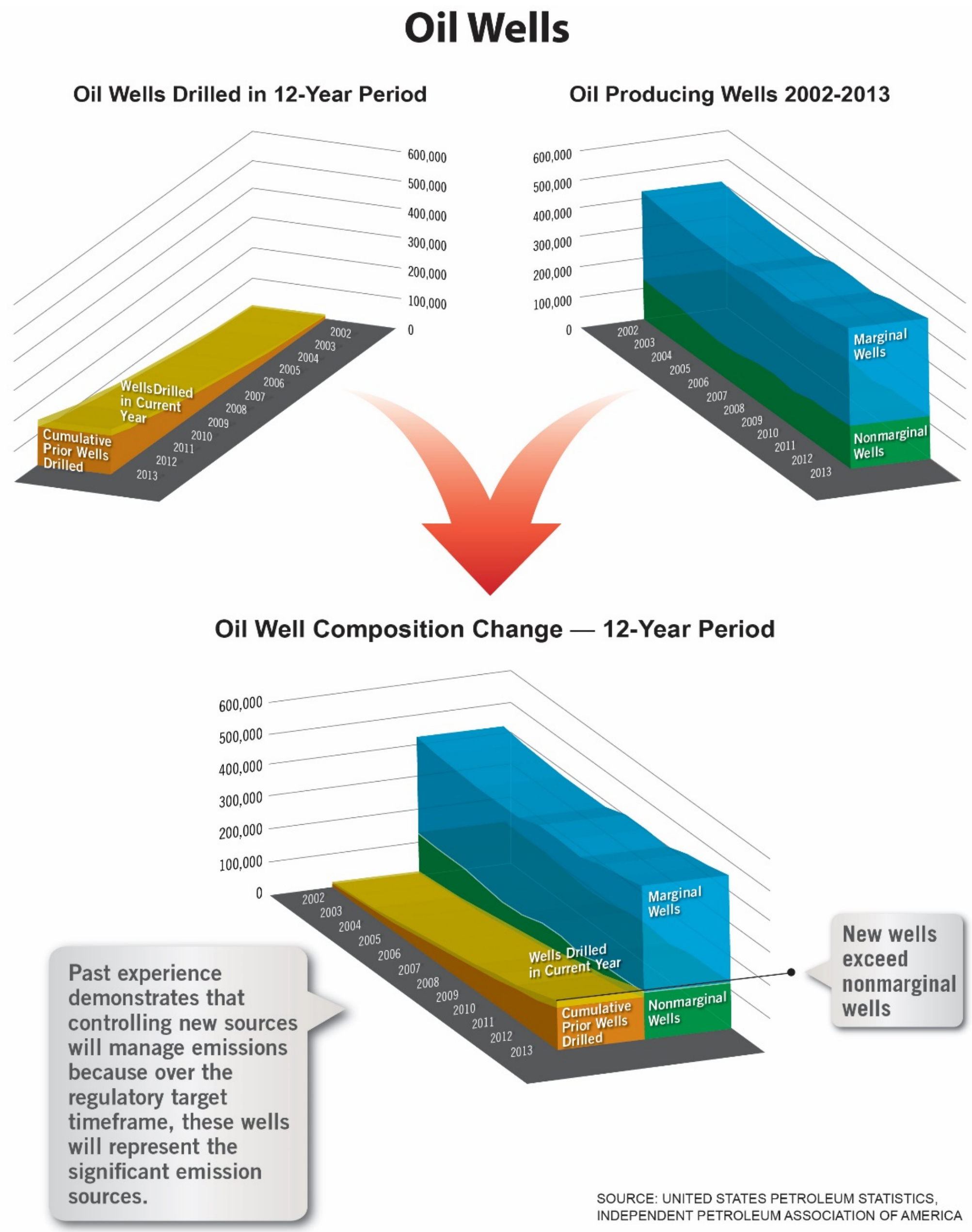
EPA is embarking on a regulatory action that has the potential to end the production of 10 to 20 percent of American oil and 13 percent of American natural gas. This production results from the operation of America's marginal oil and natural gas wells. These low production wells represent 80 percent of American oil wells and two-thirds of American natural gas wells; they average about 2.5 barrels/day of oil and about 22 mcfd of natural gas, respectively. In current economic conditions, these wells are at an economic tipping point and additional regulation would cause their failure if that regulation does not recognize this reality.

More broadly, EPA is embarking on regulations in an industry that it does not understand. As EPA Administrator Gina McCarthy was quoted as saying, "EPA's learning this industry right now because it is not an industry we regulate. We've just gotten into regulation of this so there's a lot of hundreds of thousands of small sources and EPA does not generally have a relationship with this industry as we do other sectors that we've regulated for frankly decades. But we are learning." The use of the Information Collection Request (ICR) process can provide EPA with the understanding it needs to be a fair and effective regulator. However, the pathway that is currently being taken in the ICR development will thwart rather than improve EPA's understanding of the industry.

Not only must EPA understand the impact of its regulations on America's marginal wells, it must also recognize that the universe of existing oil and natural gas wells and facilities is populated by a mixture of wells. There will be variability of oil and natural gas reservoir characteristics and production methods – e.g., primary, secondary recovery, enhanced oil recovery (EOR) – the presence of artificial lift technologies, future production dynamics, and numerous facility and pipeline configurations.

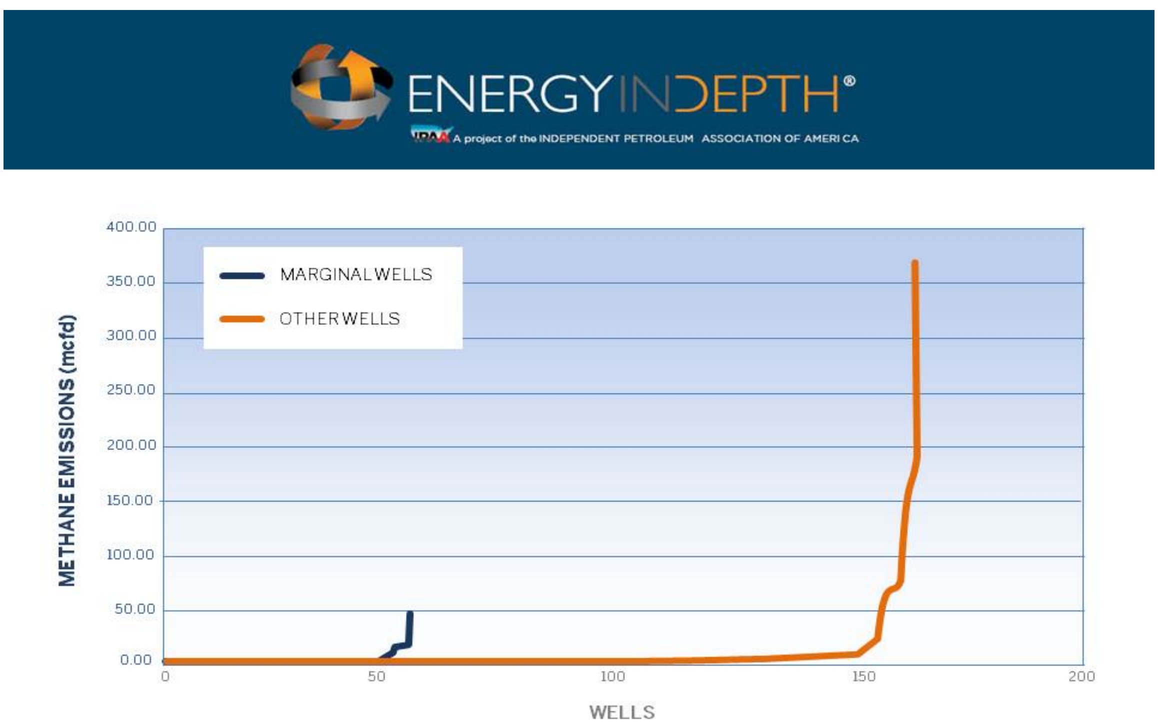
There will be a mixture of regulatory driven technologies and voluntarily applied technologies that must be taken into account. For example, by the time EPA completes its action on an existing source regulation under CAA Section 111(d), thousands of wells completed after 2012 will have implemented technology requirements under Subpart OOOO, and thousands more will have applied these same technologies under voluntary programs such as Gas STAR prior to the promulgation of Subpart OOOO. The graphs below demonstrate that, by the time this regulatory initiative is implemented, the universe of American oil and natural gas wells that are neither subject to Subpart OOOO nor marginal wells will be small and rapidly moving to marginal well status.


Natural Gas Wells
Natural Gas Wells Drilled in 12-Year Period
Natural Gas Producing Wells 2002-2013
600,000
500,000
400,000
300,000
200,000
100,000
0
2002
2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013
Wells Drilled in Current Year
Cumulative Prior Wells Drilled
Marginal Wells
Nonmarginal Wells
Natural Gas Well Composition Change — 12-Year Period
Past experience demonstrates that controlling new sources will manage emissions because over the regulatory target timeframe, these wells will represent the significant emission sources.
New wells exceed nonmarginal wells
SOURCE: UNITED STATES PETROLEUM STATISTICS, INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA



Similarly important, EPA's existing source regulatory initiative under CAA Section 111(d) falls within the regulatory requirements of Section 111. These include adequate demonstration of the technology in the industry regulated, consideration of cost, consideration of energy implications, and – specifically for Section 111(d) – consideration of the regulations' impacts on the remaining useful life of the facility. Equally important, under Section 111 EPA may distinguish among classes, types, and sizes within categories of sources for the purpose of establishing such standards. Determining the remaining useful lives of U.S. oil and natural gas fields will be variable, will be based on economics, and will be field specific (e.g., type of fluids, shifting of fluid parameters, type of equipment, current operations, etc.). Enhanced oil recovery operations are very sensitive to regulatory costs.

To date, EPA's regulatory actions relating to oil and natural gas production operations fail to reflect the understanding of the industry that is needed to create a regulatory framework to provide acceptable environmental management while providing a structure to assure that American oil and natural gas resources are developed and maintained. Both Subpart OOOO and Subpart OOOOa were developed using available information on both emissions levels and technical applicability. While some of these requirements were based on widely used technologies in oil and natural gas production, others were not – such as the fugitive emissions requirements that were based on limited information and then crafted into a system that differed from those that were used in states with fugitive emissions management programs. EPA's efforts to address existing source emissions in the Volatile Organic Compound (VOC) Control Technique Guidelines (CTG) in Ozone National Ambient Air Quality Standards (NAAQS) nonattainment areas fell completely short of any plausible analysis of whether these requirements constituted Reasonably Available Control Measures (RACM). EPA merely duplicated the New Source Performance Standards (NSPS) from Section 111(b), applying them to existing sources. Similarly, when EPA acted to reflect distinctions based on the size of a facility in recognizing that "low production wells" – the marginal wells described above – should be excluded from the Subpart OOOOa fugitive emissions requirements, it later withdrew this distinction in the final regulation, apparently based on a specious analysis by the Environmental Defense Fund, *Toward a Functional Definition of Methane Super-Emitters: Application to Natural Gas Production Sites*. This analysis purports to create a new analytical approach to define super-emitters and show that these low production wells result in significant emissions. However, analysis of the underlying data used in the study demonstrates that marginal wells emit as one would logically expect – at a much lower rate than larger wells. As the following graph of the data shows, marginal wells are minor emissions contributor.



EPA Needs to Understand the Declining Nature of Oil and Natural Gas Production

EPA's task, now, is to develop a nationwide existing facility regulation for an industry that is complex and diverse. Regulating oil and natural gas production is a different task than regulating other segments of oil and natural gas processing. When an oil refinery is constructed, it is designed to process petroleum volumes within a specific range. It operates more or less at a constant feed rate, and its air emissions are predictably constant. Oil and natural gas production starts at an initial production rate and then begins to decline as the resource is extracted from its reservoir. Consequently, its potential to emit methane and volatile organic compounds is highest when production begins and then declines over time. Think of an inflated balloon that releases a strong flow of air when pressure on its neck is relaxed but as the balloon deflates, the air release dramatically slows. The physics of oil and natural gas production emissions suggests that equipment designed to manage gas flow when the well is producing 5000 mcfd will not be stressed to release gases when the well has declined to the average marginal natural gas well rate of 22 mcfd. Certainly, these are issues that EPA must understand to craft an appropriate national regulatory program, including the creation of subcategories of operations. At issue, then, is whether the ICR provides the information needed to create this level of understanding.

EPA Needs to Utilize Existing Agency Resources and Resources Publicly Available at State Agencies

Similarly, in addition to understanding the implications of an industry with inherently declining unit production, EPA needs to understand the scope and diversity of the industry. It needs to understand these aspects to assure that its ICR provides the information it needs to design a regulatory system. It has available to it the resources to better understand the nature of American oil and natural gas production through both free resources held by state permitting agencies and existing information from DrillingInfo that the Agency has used in the past. State permitting agencies have detailed information on every operating well in the State. Information includes details on the depth of the well, its horizontal legs, its producing zones, its well construction, its location, the characterization of its crude oil, and more. Production information is available, including volumes of oil, of natural gas liquids and of natural gas. In some cases, permit agencies have information on gas composition in operating vessels. While some of this information is held by air regulatory agencies, most of it would be posited with oil and natural gas production well permitting agencies. DrillingInfo should have historic production information on a well-by-well basis and include production composition information and well location. By using location information from these multiple data sources, EPA could compile an information grid that would identify areas showing key information on oil production and natural gas production, conventional wells and non-conventional wells (such as shale oil and shale gas), marginal wells and large producing wells, heavy oil and light oil, sour crude and sweet crude, enhanced oil recovery operations (including carbon dioxide injection wells) and secondary recovery operations. By using these resources – and with the assistance of the industry – EPA could create a far better ICR process.

EPA Needs to Obtain Information That Reflects Emissions Throughout the Year

As EPA tries to seek information in an ICR, it must look toward the use of that information in designing regulatory requirements that apply throughout the range of operations at an oil and natural gas production facility. As previously described, the diversity of operations across the nation is extensive. And, within this diversity, industry must cope with challenges that vary from season to season. Oil and natural gas production operations are conducted in all types of weather. Weather can change the nature of air emissions; weather differs from region to region. Some regions face larger extremes than others. North Dakota, for example, can range from subzero temperatures in the winter to 100° and more in the summer. EPA's past reliance on limited studies that do not reflect the full range of weather in one area or its application of emissions analyses from areas where the predominant weather circumstances do not reflect where it is being applied must be avoided in developing appropriate existing source regulations. At issue, then, is whether the ICR or emissions data that EPA uses fully describes the emissions profile of the facilities to be regulated.

Section 111(d) Requires EPA to Understand the Implications of Regulations on the Remaining Useful Life of a Facility

Another key aspect of regulating existing facilities involves assessing the implications of regulations on the remaining useful life of the facility. Oil and natural gas production has often been described as a "food chain" industry. This characterization arises from the historic practice of companies selling wells that are less profitable to them to other companies that can more profitably operate them. Over the long term, this practice has resulted in an extensive network of marginal wells that are operated primarily by small businesses. In the current economic climate, these marginal wells are operated at an economic tipping point where regulations can result in their shutdown. Once shut down, marginal wells are lost to future production because the cost of reopening them – when it might be technically feasible to do so – is too high to justify the expenditure. Past EPA regulatory actions have been NSPS that are directed at new facilities where the cost of control equipment can be considered in the economic determination of whether to drill a well. These determinations did not address consideration of the regulatory costs on the life of the operation. In reality, when EPA changed the Subpart OOOOa fugitive emissions program to cover marginal wells, it adversely affected the life of all future oil and natural gas wells. By imbedding in the cost of operating these wells the costly and cost-ineffective Leak Detection and Repair (LDAR) program, EPA's requirements will prematurely end the life of these wells. Marginal wells can produce for years at low levels, adding to the production of American oil and natural gas, but the added LDAR costs will make these well unappealing for purchase by small businesses because of the embedded LDAR costs. EPA's only venture into regulating existing oil and natural gas production operations is its action to create VOC CTG in Ozone NAAQS nonattainment areas. The regulatory standard for a CTG is RACM. In its *Federal Register* notice regarding the Release of Draft Control Technique Guidelines for the Oil and Natural Gas Industry, EPA provides a pertinent description of the RACM process:

> Section 172(c)(1) of the Clean Air Act (CAA) provides that State Implementation Plans (SIPs) for nonattainment areas must include ''reasonably available control measures'', including ''reasonably available control technology'' (RACT), for existing sources of emissions. Section 182(b)(2)(A)of the CAA requires that for Moderate Ozone nonattainment areas, states must revise their SIPs to include RACT for each category of VOC sources covered by a CTG document issued between November 15, 1990, and the date of attainment. CAA section 182(c) through (e) applies this requirement to States with ozone nonattainment areas classified as Serious, Severe and Extreme.
>
> The CAA also imposes the same requirement on States in ozone transport regions (OTR). Specifically, CAA Section 184(b) provides that states in the Ozone

> Transport Region (OTR) must revise their SIPs to implement RACT with respect to all sources of VOCs in the state covered by a CTG issued before or after November 15, 1990. CAA section 184(a) establishes a single OTR comprised of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont and the Consolidated Metropolitan Statistical Area (CMSA) that includes the District of Columbia.
>
> The EPA defines RACT as ''the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility'' (44 FR 53761, September 17, 1979).[1]

While this description is accurate, EPA wholly failed to meet the test of identifying "control technology that is reasonably available considering technological and economic feasibility."[2] Instead, EPA merely duplicated the NSPS requirements from Subpart OOOO and the then-proposed Subpart OOOOa as CTG. In using Section 111(d) as the basis for its possible national emissions standard, EPA must look to still other technology tests. As stated above, it must consider the impact of the regulatory requirements on the remaining useful life of the facilities.

EPA Needs to Utilize Its Authority to Create Subcategories

Under Section 111, EPA has the authority to create and use subcategorization to focus regulations that are suited to appropriate elements of the industry. EPA needs to utilize this authority in the context of existing source regulation under Section 111(d) because of the significant diversity of the American oil and natural gas production industry.

Subcategorization issues arise when EPA must consider the need to distinguish the variable types of oil and natural gas production operations. Most of EPA's recent focus has been on NSPS regulations primarily directed at the nonconventional production that has dominated recent American oil and natural gas development. But, in moving to existing sources, EPA must recognize that the overwhelming majority of wells will be conventional production, principally marginal well operations. The variety of these wells will range from the non-conventional shale oil and shale gas wells that have emerged over the past decade, to historic conventional crude oil production, to coal bed methane wells, to EOR production operations that by themselves utilize different technologies from steam to carbon dioxide. Emissions profiles for these operations will differ; their economic capability to absorb additional regulatory requirements will be a key factor in assessing the BSER requirements that can be applied.

For example, adding controls to reduce or eliminate methane emission from existing EOR production operations is not a "one-size-fits-all" proposition due to the wide variability in oil reservoir characteristics, production dynamics, and numerous facility-specific equipment configurations across the United States. For retrofit designs, an accurate estimation of the cost to install and operate methane controls must include consideration of many direct and indirect factors, which are site-specific in nature. Indirect costs factors consist of current equipment

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[1] Release of Draft Control Techniques Guidelines for the Oil and Natural Gas Industry, 80 Fed. Reg. 56,577, 56,578 (Sept. 18, 2015).

[2] *Id.*

design and operation, piping size, mechanical integrity, pressure relief controls, equipment cleanout, etc. Determining these indirect costs can add substantial capital and operating costs to the controls.

These are reasons for EPA to devote the time and effort to fully understand the different aspects of the industry. It also argues that EPA needs to fully understand the economics of existing operations of the industry because – unlike new sources – existing sources must operate in the situations where they are. At issue, then, is whether the ICR is designed to generate the information that is needed to understand these facts.

In the draft ICR – both Part 1 and Part 2 – EPA solicits virtually no economic information. The only cost data it seeks is in Part 2 with regard to control devices. Compare this to EPA's DETAILED QUESTIONNAIRE FOR THE COALBED METHANE EXTRACTION SECTOR with regard to Effluent Limitations Guidelines that had 37 pages devoted to acquiring information on the economics of coal bed methane operations. While we would not suggest that the scope of that questionnaire should be duplicated in this ICR, we are certain that EPA cannot fully assess the implications of existing source regulations in the absence of any economic information. EPA may argue that the issue of economics is not the driving force to determine the level of regulation under Section 111(d), but we believe that the BSER analysis and requirements to consider the remaining useful life of facilities require EPA to understand the consequences of its regulatory options. It cannot do so with the questions it includes in the draft ICR.

EPA Needs to Assure That the Information It Collects Accurately Describes the Industry and Can Be Acquired at a Reasonable Cost

As EPA crafts the ICR, another challenge relates to gathering the statistically significant information to accurately characterize the industry in order to design a regulatory structure that meets the criteria of Section 111. The oil and natural gas production industry spans the breadth of American businesses. IPAA periodically assesses the profile of independent producers. The most recent profile suggests that the median size for an independent producer is 12 full-time employees. Clearly, the industry ranges from some of the largest companies in the world to numerous small companies. Correspondingly, larger-production wells tend to be operated by larger companies, and smaller companies operate marginal wells. To understand the implications of regulatory options on this scope of operations requires that adequate data be collected across the breadth of the industry. But ICRs have a history of requiring substantial expenditures by companies to complete them. Under current conditions, small business operators do not have the resources to fully respond to the depth of questions that EPA likely needs to ask to properly understand the industry. Therein lies the dilemma – how to acquire the statistically significant information that EPA needs at a cost that the small business component of the industry can afford.

EPA's Current Actions Are Undermining Its Ability to Develop Sound, Cost Effective, Fair Regulations

Set against the multiple challenges that EPA must manage to develop a sound, cost effective and fair regulatory program is EPA's rush to develop an ICR – actually two ICRs. While detailed observations on the ICRs will be presented subsequently, the broader process demonstrates that the EPA actions will prevent it from developing an effective regulatory system.

Because EPA has not spent the effort to understand the breadth of the oil and natural gas production industry, it has created draft ICRs that fail to ask the right questions. EPA's information requests appear driven to ask questions only about issues that EPA has hypothesized are significant based on the regulations it produced in Subpart OOOO and Subpart OOOOa and anecdotally understand to be important. Wholly absent from the draft ICRs are questions addressed to the operating costs of these wells.

EPA is presenting two ICRs for approval. The first would capture hundreds of thousands of wells, and the second would be targeted to obtain detailed information on a smaller number of wells. It is wholly unclear how the two ICRs work together. More significantly, there is no basis to assume that EPA can identify recipients for the detailed ICR without obtaining information from the first ICR. As stated above, EPA will need to categorize the industry extensively based on type of production (crude oil, natural gas, natural gas liquids and combinations), on specific crude characteristics (heavy or light, sweet or sour), on size of well (large or marginal), on specific well conditions (Gas to Oil Ratio – GOR), on date of initial operation (before or after Subpart OOOO, for example), on location (basin of operation, rural or urban, state), and other factors to achieve a statistically significant sample that reflects these diverse factors.

EPA raises this issue in its *Federal Register* Notice stating:

> Developing an appropriate sampling size for the onshore production industry is complicated by the number of factors that could impact the types of processes or equipment present at the site and the magnitude of emissions from these sources. Therefore, the Agency considered further stratification of the production industry segment into separate populations based on differences in the type of well (oil or natural gas, vertical or horizontal drilling, or further distinctions based on gas-to-oil ratio), the type of formation, and the production basin. At this time, the Agency has limited information on means to characterize individual facilities or wells by formation type or well drilling type (vertical versus horizontal wells). However, the Agency does have estimates of the number of wells in a given basin and has estimates of the gas-to-oil ratio (GOR), from which we designate well type for nearly all wells. Therefore, the Agency considered two options for establishing different populations within the production segment: Option 1, which is based on the well type using GOR ranges, and Option 2, which is based on regional groupings of basins.
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> Option 1, which considers populations based on well types, defines the following five populations based on GOR:
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> 1. Heavy Oil (GOR ≤ 300 standard cubic feet per barrel, scf/bbl)
>
> 2. Light Oil (300 < GOR ≤ 100,000 scf/bbl)
>
> 3. Wet Gas (100,000 < GOR ≤ 1,000,000 scf/bbl)
>
> 4. Dry Gas (GOR > 1,000,000 scf/bbl)
>
> 5. Coal Bed Methane
>
> Most of these well type categories have historical significance, such as the GOR of 300 scf/bbl included in the applicability of the Oil and Gas NSPS requirements

for well completions (40 CFR part 60, subpart OOOOa) and the GOR of 100,000 scf/bbl delineation between oil and gas wells used in the U.S. Emissions Inventory for GHG Sources and Sinks. The delineation between "wet" and "dry" gas wells was developed for this ICR to gain information on "wet" gas wells because these gas wells have been found to have higher VOC content and, as such, are of particular interest in this information collection effort.

Option 2, which considers regional groupings of basins, defines the following five populations based on basins (geological provinces) defined by the American Association of Petroleum Geologists:

1. East: Basins 100 to 190
2. South: Basins 200 to 290 and Basin 400
3. Midwest: Basins 300 to 395
4. West Texas: Basins 405 to 440
5. West: Basins 445 to 895

Option 1 (populations based on well type) will ensure that a statistically significant number of each well type is sampled. This is important because there are fewer wet gas wells and coal bed methane gas wells than heavy oil, light oil, or dry gas wells. However, because of the differences in the number of wells within each population, analyses using the data must use these classifications (or weighting factors) to develop nationwide assessments. The regional populations are more similar to each other in terms of the number of wells in each region, but weighting factors would still be required to perform nationwide assessments separate from these defined regions.

Based on a desire to have no more than a 10-percent error (*i.e.,* +/−10 percent) in the estimate of an average value at a 95-percent confidence interval and 90-percent power to differentiate an effect size of 0.2, the target number of samples required for large populations was determined to be 385 (additional detail regarding the determination of the target sample size using the statistical sampling approach is provided in Part B of the Supporting Statement for this ICR, which is included in Docket ID No. EPA-HQ-OAR-2016-0204 at *http://www.regulations.gov*). Consequently, because the number of production facilities in each population is relatively large compared to the target sample size, the overall costs of the two survey options for production facilities are nearly identical. We are specifically requesting comment on these two options for developing population categories within the production industry. We recognize that other alternatives may be viable, such as defining the entire production industry as one population and developing sampling requirements based on the accuracy and precision needed to characterize any subcategory of the production population that represents, for example, 20 percent of the total production wells. In this example, 1,925 (5 × 385) samples from the production population would be required. All respondents would have equal weight, so analyses could be conducted without having to consider weighting factors, but analyses for categories of wells with less than 20 percent of the population would have less accuracy and precision. As there are many potential factors to consider for the production population, we also request comment on other potential methods to define populations of production wells in order to adequately characterize the various potentially important differences in production facilities.

While each of these options has some merit regarding categorizing wells – Option 1 by type, Option 2 by location – neither gets to key significant factors. For example, production rate and ownership are factors that have a far more compelling role in determining emissions profiles and ability to absorb regulatory costs. As stated above, despite allegations from professional "Keep It in the Ground" environmental groups, marginal wells will not have the emissions profile that justifies regulations comparable to those imposed on new sources. Clearly, EPA needs to better understand this reality and needs to categorize information to allow such analysis. Similarly, most of these marginal wells will be owned by small businesses, and the combined reality of their financial capacity and the nature of marginal well production will have a significant bearing on assessing the impact of regulation on their remaining useful life. The date of initial production can be an important factor to categorize wells because it will identify wells that are subject to Subpart OOOO and will have a different emissions profile.

EPA states that "At this time, the Agency has limited information on means to characterize individual facilities or wells by formation type or well drilling type (vertical versus horizontal wells)." EPA does not describe the nature of its limitations. It mentions that it "collects information on the greenhouse gas (GHG) emissions from oil and gas facilities under 40 CFR part 98, subpart W, of the Greenhouse Gas Reporting Program (GHGRP)." But, it does not indicate whether it plans to use this information in some format. As described previously, EPA also has access to well data through DrillingInfo, and it could access information publicly available from state permitting agencies. Without finalizing the ICR, these resources can provide EPA with a framework of information on location, size, and type of well – including formation type and well drilling type. Using that information, EPA can far better categorize oil and natural gas production facilities and better frame its ICR to validate that information while focusing on key information that is not reflected in the current draft proposals. It would also define more granular information on location than the inferred information in the Option 2 presentation. That is, there are many basins that can have significantly different well operations. For example, the Permian Basin in Texas and New Mexico is now an active shale oil production region but it also contains significant conventional wells, many of which are marginal wells. Categorizing wells using broad location areas will fail to give the Agency the depth of understanding it needs to understand the factors needed to write regulations.

EPA needs to structure the framework described above and then use that material to fashion its initial broadly distributed ICR to fill out the composition of categories that reflect location, size, type of well (oil or natural gas, conventional or non-conventional), and ownership. This approach would permit EPA to create its narrower, more detailed ICR to assure that it obtains statistically significant information on the various categories and includes the more extensive information needed to address the range of issues needed for regulation.

The current proposed ICRs will not provide such information.

Specific Issues

Before presenting specific issues regarding the elements of the draft ICR, it is essential to address the serious questions related to the time to complete the ICR elements and EPA's perception of its cost.

We believe that the time allowed for industry to complete both Part 1 and Part 2 is inadequate and should be revised. Allowing extra time to complete this ICR will not materially affect EPA's ability to evaluate the survey results, but it will reduce the burden for industry in several important ways.

There are two different scenarios to consider here. As we have recommended above, the first scenario would have EPA send ICR Part 1, have it completed, analyze it, and use it to provide a better framework for ICR Part 2. Then, ICR Part 2 would be sent to a subset of producers. The second scenario is based on EPA sending both Parts concurrently. If that path is chosen, EPA would not use Part 1 to inform its Part 2 requests. While we encourage EPA to release Part 1, evaluate it, and make necessary changes before it releases Part 2 based on what it learns, we recognize that EPA could choose the second scenario. Therefore, if that scenario is chosen, it makes little sense to have Part 1 due within 30 days.

Since any analysis of the ICR will incorporate both Part 1 and Part 2 data, EPA will not be able to fully analyze its data until both Parts have been completed. While EPA could gain some time by inputting data from Part 1, pending submission of Part 2, this slight administrative advantage is outweighed by the burden on industry to comply with the unreasonable 30-day deadline. EPA would gain greater insight if it began analyzing data already available from state agencies and DrillingInfo, while allowing for both Parts 1 and 2 to be submitted concurrently.

It adds little value to have an overly-aggressive timeline on Part 1 when EPA will ultimately need to wait until Part 2 results are in before completing its analysis. Additionally, the amount of data EPA is requesting from Part 1 is significantly higher than for Part 2 in terms of number of sources and companies impacted, so it would be logical to allow additional time for that request. We are also concerned that 30 days may also prove inadequate for Part 1 given that it intends to mail its ICR. It may take several days or even weeks to get the requests to the proper contacts within every company. Thus, the 30 days allowed by EPA may be effectively even less for many companies.

For Part 2 of the ICR, EPA appears to have grossly underestimated the sheer volume of data it is seeking. Its proposed timeframe of 120 days is inadequate. We urge the EPA group leading the ICR effort to reach out to the EPA's enforcement group currently working on CAA Section 114 requests in North Dakota for oil and natural gas facility and emissions information. Given the similar nature of the ICR and these 114 requests, the enforcement group can likely give the ICR team a more accurate understanding of the magnitude of this undertaking and the amount of time that will likely be required.

In addition to the burden on agency resources to conduct Part 2, the burden on industry will be similarly daunting. Part 2 contains a remarkable breadth and depth of data that will likely not be readily available for many facilities. For example, EPA is including isolation valve activation emissions estimates in its request but this information is not currently collected in the GHGRP or under New Source Performance Standards (NSPS) Subpart OOOO or Subpart OOOOa. This will be a particularly time-consuming request to fulfill, and EPA does not appear to have fully accounted for these types of burdens in its timing estimates.

Completing EPA's request may also require respondents to commit to significant field and travel time. Given EPA's intent to release this ICR during the wintertime, travel logistics to remote field locations may be further complicated by the holiday season, inclement weather, and seasonal closures. Moving into the spring, there can be issues with wildlife impacts to consider. The request will also overlap with many annual reporting requirements, including for EPA's GHGRP and state reports. This is especially problematic because many company greenhouse gas experts who will be working on GHGRP reporting will also be responsible for the ICR. Instead, we recommend EPA target the end of the third or fourth quarter for its reporting deadline.

The compressed timeframe may also impact the overall accuracy of the data collected. For example, emissions data collected during a short span of the year may not accurately reflect emissions around the country on a year-round basis. In places like Wyoming, Utah, and North Dakota there can be extensive use of heat trace pumping equipment during winter months. Extrapolating year-round usage trends about this equipment based on single measurements of emissions during the winter would be inappropriate. Similarly, emission rates may differ greatly during the summer in places like New Mexico and Texas, where high temperatures will significantly affect the performance of field equipment. The most sensible way to address these many different considerations is to allow operators additional time to complete EPA's request. That way, they can plan for the unique regulatory and operational demands of each facility surveyed. A longer timeframe to conduct the survey will also give EPA a more accurate snapshot of industry operations throughout the year.

Both Part 1 and Part 2 of the ICR will be significant burdens for industry with numerous factors that will likely add time and expense, so we encourage EPA to maximize flexibility in its timeline. Since there is no clear added value in receiving Part 1 surveys within 30 days, we urge EPA to allow the same deadlines for both Part 1 and Part 2. And since Part 2 requirements may be extremely difficult and time-consuming, requiring field trips that could be delayed by seasonal or weather-related issues, we recommend EPA allow a minimum of 180 days to respond to its ICR.

We believe EPA's perception of the industry leads it to underestimate the complexity of its requests. For example, EPA looks at the number of wells in operation and perceives that a facility is comprised of two wells. However, there are many formulations of operations, and the development of the technologies to produce shale oil and shale natural gas has dramatically shifted the nature of operations. Horizontal drilling has allowed the industry to alter its footprint by consolidating a number of wells on one well pad. Consequently, it is commonplace for shale wells to have 10 or 12 wells on the same site. Perhaps, these changes in the industry influence EPA's underestimation of the time and cost for completion of the draft ICR. For example, one of the larger member companies would significantly differ from EPA's estimate of 30 facilities (60 wells); it would have more like 2,000 facilities (with 11,000 wells). Correspondingly, in assessing realistic times to complete the information EPA is seeking, the number of hours is far above those estimated by EPA, and the costs for Part 1 would be close to 200 percent of EPA's estimates – around $150,000 – and for Part 2, the costs would be between $225,000 and $450,000 depending on the number of Part 2 questionnaires received.

There are similarities in requested data collection under ICR Part 2 when compared with EPA's ongoing Section 114 requests. Specifically, for Sections 2A - Facility Information, 2B - Well Sites, On-Site Tasks 3A and 3B (Pneumatic and Equipment Counts, respectively), these Items do not adequately account for additional travel time/costs. Items 3C and 4 - Tank Feed Sampling and Analysis/Results, respectively, do not adequately account for vendor sampling costs (too low by a factor of 1.5), for protocol review and preparation, sampling preparation and oversite and company travel time and costs. Lastly, Item 5 – Information Submittal, does not take into account preparation of data for e-GGRT entry, registration of personnel in e-GGRT, and overall report review by corporate legal and EHS staff which increases time and costs substantially. On the basis of comparison with similar 114 items listed above, an IPAA member calculated that its Part 2 costs would be 2.3 times EPA's estimate.

A portion of the differences in assessing costs and time relates to EPA's perception of the industry and of a facility. This impact is more clearly seen in the detailed information required in Part 2. EPA wants data framed in its image of a facility, but industry collects data to report for other purposes such as well data for state permitting and tax reporting. Reframing the data for the ICR report is more than a simple exercise; it is essentially the creation of new information.

All of this is further complicated by EPA's stated intent to distribute the ICRs by October 30, 2016. Given the August 2 deadline for these comments and the 30-day comment period for the Office of Management and Budget (OMB) review of the ICR, EPA and OMB would have approximately 60 days to analyze all of the submitted comments. Sadly, this suggests that EPA has little interest in addressing any information other than minor changes to its proposed ICRs. Assuming that EPA meets its October 30 objective, ICR compliance would then compete with industry efforts to initiate its compliance with Subpart OOOOa and, in early 2017, with the preparation of data for Subpart W submission. Independent producers' staff available to respond to the ICR is limited, particularly in the current economically constrained circumstances. For small business marginal well operators the challenge will be larger.

The issue of small business participation in the ICR is a significantly larger one than EPA perceives. In its "SUPPORTING STATEMENT FOR PUBLIC COMMENT INFORMATION COLLECTION EFFORT FOR OIL AND GAS FACILITIES" document, EPA casually states with regard to small entities:

> The Part 1 survey is required for all operators of oil and gas production facilities and all respondents to the Part 1 survey will be subject to the same requirements. The Part 2 survey employs a sampling approach of facilities in each industry segment, and facilities selected to complete the Part 2 survey will be subject to the same requirements. The EPA expects that a portion of the respondents to both Parts 1 and 2 may be small entities; however, any individual small entity would be expected to have fewer sources so its response burden will be minimized.

While EPA may be correct that "any individual small entity would be expected to have fewer sources….", this may not be the case. Regardless, small entities have limited ability to devote resources to complete the ICRs, particularly ICR Part 2. And, therein lays the dilemma. With the overwhelming majority of American oil and natural gas wells being marginal wells, EPA needs to fully grasp the nature of that component of the industry – particularly to address the impacts of regulations on the remaining useful life of the facility. Yet, this component of the industry has the least capacity to have the resources to manage completion of the ICR.

Following are specific issues related to the draft ICR.

1. ICR Part 1 Data Collection

a. General Facility Information

The Part 1 request contains several pieces of facility data that may be problematic or confusing to report. Oil and natural gas production wells are frequently owned by multiple parties with one designated as the operator. Consequently, as a general comment for both Part 1 and Part 2, we believe that EPA clarify that only wells and equipment operated by the company are included in the company's response to EPA. This will avoid duplicative reporting by the non-operating owners.

However, the definition of "onshore petroleum and natural gas production facility" and "facility" in Part 1 needs to be removed to avoid confusion and inconsistencies in information received. EPA defines several terms that make it confusing for operators to interpret the data requested by facility in Part 1. Specifically, EPA defines "facility", "well site", and "onshore petroleum and natural gas production facility" in Part 1, but these definitions are not consistent and could lead operators to inconsistently report Part 1 data due to the conflicting definitions. We are concerned that these terms will cause confusion over which pieces of equipment are intended to be included, and where the boundary should be drawn for reporting. For example, if there are two adjacent wellheads under common control but feeding into different central tank batteries, it is unclear how an operator should group the wellheads and equipment. EPA's definition of 'facility' in Part 1 that specifies "…located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control…." could result in grouping two wells that feed into separate tank batteries but happen to be physically adjacent into one facility. Producing wells may be co-located with other facilities, such as a compressor station, central tank battery, or gas processing plant that processes crude oil and natural gas from other locations. EPA's definition of "onshore petroleum and natural gas production facility" indicates that any production facility co-located with a well would be included as part of a facility, but a central tank battery that processes production from wells but has no wells on the surface site would be excluded completely from Part 1. If it is EPA's intent to collect data from the wellhead and any associated production equipment, these proposed revisions will accomplish that goal without introducing complicated common control and adjacency analyses. This approach would facilitate appropriate extrapolation of the model plant data collected in Part 2. Further, we do not believe EPA intends to have daisy-chained facilities that include hundreds of wells. Therefore, we recommend that EPA use only the term "onshore well-site"; it should exclude usage of the terms "facility"' and "onshore petroleum and natural gas production facility".

EPA is requesting information on the number of employees. One of the purposes of this question appears to be determination of whether the operator is a small business. EPA could more easily address this question by providing the necessary definition of a small business in the oil and natural gas production industry and have a pull down "yes" or "no" response.

b. Plugged and Abandoned Wells

The facility-wide count for capped or abandoned production wells is a highly problematic request and should be excluded from the survey for several reasons. Oil and natural gas has been developed domestically since the 1850s, and, historically, recordkeeping was scant for old wells.

In many cases, today's large producing basins have legacy oil and natural gas production that dates back decades, along with many abandoned wells. Many of these plugged and abandoned wells are so old that today's operators may have no records of them. Many other wells have been exchanged or sold numerous times over their lives. Records from prior owners or operators can be very difficult to obtain in these situations. While we can appreciate EPA's interest in old plugged and abandoned wells, this ICR is an inappropriate way to gather more information about this population of wells.

In addition to being very difficult to comply with, the collection of plugged and abandoned well data offers virtually no benefit in terms of information to be used to regulate new and existing oil and natural gas production facilities because there are no emission sources related to plugged and abandoned wells. Current state regulatory requirements for well plugging and abandonment procedures are robust, and it would be infeasible for EPA to attempt to regulate wells abandoned decades ago. Since this information will not be necessary for proper performance of EPA functions, it should be removed from the ICR.

c. Distance to Gathering Lines

Distance from facility to the nearest natural gas gathering line is another category that is problematic and requires modification. Distance to natural gas gathering lines, in addition to offering limited utility for improving EPA's understanding of industry, is logistically difficult to determine. Much like distance to the field office, addressed below, calculating distance to natural gas gathering lines creates a burden on respondents that far outweighs the useful benefit of this information. A more appropriate question is whether the facility is connected to a natural gas sales line, rather than distance to the nearest gathering line.

All natural gas wells should be exempted from this requirement. No rational operator would develop a natural gas well without takeaway capacity. For natural gas wells, reporting the distance to gas gathering lines would not be a worthwhile exercise.

Similarly, an oil well that is connected to gas gathering should simply be able to satisfy EPA with a "yes" or "no" answer. Once the connection to gathering has been made, the distance becomes largely irrelevant.

For other wells, determining distance to gas gathering would be a time-consuming mapping exercise for every facility with questionable benefits. If EPA is trying to use distance to gathering lines as a proxy to assess whether oil wells are emitting methane rather than selling it, it is a poor proxy because of the many other factors that affect that choice. For example, the relative proximity of gas gathering lines is often irrelevant when capacity issues come into play, which is often the primary driver in areas where gas capture rates are lower. Furthermore, existing sources will be connected to gathering lines where it is feasible to do so. The distance to the nearest gathering line is largely irrelevant and may even be unknown.

If an operator has an existing contract with a specific midstream operator to tie in all wells in an area to their pipeline, there may be a closer gathering line that the survey respondent is not going to connect to for contractual or logistical reasons. This could include an operator that may not have rights-of-way to connect to the closest gas gathering line or have gas that is not of sufficient quality to connect to the nearest gathering line.

d. Distance to Field Office

Distance from facility to field office is a problematic requirement. Like the distance to natural gas gathering, this will require time-consuming mapping, and, like distance to gas gathering, this information is of limited utility. EPA appears to be using this information as a proxy to assess how an operator services its operations. Distance to the nearest field office is not a useful proxy for several reasons.

First, most operators service their well sites using assigned or contracted personnel who visit sites on a specific schedule depending on its size and production. Typically, these visits are sequential and start, not at the field office, but at the roustabout's home. Trips to the field office would depend on actions that needed to be done there, not at the well site.

Second, if the field office distance is being viewed as a proxy for LDAR actions, EPA needs to understand that, for most companies' LDAR program, companies have trained teams that move through their operations on fixed schedules. They are not deployed from field offices.

Given that calculating the distance to the nearest field office will be a particularly time-consuming request, we strongly recommend EPA strike it. However, if the Agency sees any remaining value to the Distance to Field Office query, it should have a pull down set of ranges that can be more simply answered (e.g., 0-10 miles, 10-25 miles, 25-50 miles, etc.).

e. Storage Tanks

We understand that the storage tank information requested in Part 1 will be used to extrapolate information on the more detailed information on tank type and size in Part 2. This should be reasonable if EPA is able to distinguish between different types of operations in Part 2. That is, the Part 2 questionnaires need to be reflective of both the type and size of oil and natural gas production because the storage tanks will differ depending on type and volume of production.

f. Facility Electrification

While we can certainly appreciate EPA's interest in the availability of electrification, this request is problematic and inappropriate for the Part 1 survey.

While we believe that EPA's perspective on this question is based on an assumption that it can be readily answered, it is not a simple task. In many cases, the availability of electricity for every facility will not be an easy determination. Instead, it will require industry to review utility bills for entire fields and determine where electricity is being utilized. Although the presence of electricity could be an important consideration for understanding what control technologies could be utilized, the practical reality of how field electrification is billed makes this an extremely time-consuming request that will be difficult to determine with certainty for every facility. We recommend instead that EPA make availability of electricity part of its Part 2 request.

Additionally, we recommend that EPA clarify that facilities using temporary generators but that are not connected to the electrical grid would not be considered electrified. These generators do not necessarily remain onsite and may not have the capacity to operate instrument air pneumatic systems or other electrical systems. It would be inappropriate to deem these sites to be electrified.

g. Liquids Unloading

Given the strong evidence based on extensive research that liquids unloading is not suitable for prescriptive one-size-fits-all regulation, we are deeply troubled by EPA's decision to propose it in its ICR. Furthermore, the mere occurrence of liquids unloading reveals little information of use to EPA, as it does not address the timing, frequency, technique, or other pertinent information about the process. EPA recently declined to develop NSPS for liquids unloading in its Subpart OOOOa rulemaking. It would be both illogical and counter to CAA procedures to develop existing source standards in the absence of new source standards.

Notably, EPA's decision to avoid regulation of liquids unloading did not come lightly. EPA conducted an exhaustive examination of liquids unloading practices and concluded:

> Data reviewed also show that liquids unloading events are highly variable and often well-specific. Furthermore, questions remain concerning the difficulty of effective control for those high-emitting events in many cases and concerning the applicability and limitations of specific control technologies such as plunger lift systems for supporting a new source performance standard.

As a result of its analysis, EPA declined to regulate liquids unloading in its proposed NSPS Subpart OOOOa. Similarly, the Colorado Department of Public Health and Environment (CDPHE) recognized that operators need flexibility to employ best management practices on a well-by-well basis. CDPHE went on to recognize that automated plunger lifts are not pollution control devices and are not used in the field unless the well design, geologic conditions, and gas content are appropriate for it. Therefore, we encourage EPA to remove liquids unloading from the ICR entirely. Successful approaches to addressing liquids unloading in Colorado and elsewhere have steered away from prescriptive regulation and instead focus on best management practices and reporting requirements.

Moreover, this question is entirely unbounded. Regardless of whether liquids unloading occurred once in the past year or once over the life of the well, respondents will provide the same answer as this section is currently written. The reality is that liquids unloading will be highly variable over the life of the well and can change in response to shut-ins and other events. The liquids unloading questions in ICR Part 1 offer no meaningful insight into the practice and are therefore not necessary.

h. Focus on Pre-OOOO Facilities

In order to maximize the utility of the ICR, we recommend that EPA focus on facilities existing prior to Subpart OOOO. This is particularly important for two reasons. First, many of the processes being surveyed are controlled through NSPS Subpart OOOO and Subpart OOOOa, and therefore EPA should have an accurate understanding of the control requirements in place. Subpart OOOO and Subpart OOOOa have clear emission thresholds that indicate how and when facilities will be controlled. Second, for the purpose of developing existing source rules, cost and emissions data on older sources is far more useful than data on new facilities. New control costs are applied very differently to existing facilities. Therefore we recommend that EPA focus on sources constructed prior to the Subpart OOOO applicability date.

i. Number of Separators

EPA should be aware that oil and natural gas operations often utilize two-phase separators, three-phase separators, or both at productions sites. A simple count of separators may not provide

EPA the information it is seeking. We understand that EPA will be seeking more detailed information in the Part 2 questionnaire; however, as we noted on Storage Tanks, extrapolation of Part 2 information will depend on whether it accurately samples the breadth of the industry.

2. ICR Part 2 Data Collection

a. Feed Material Composition Analysis

One of the most detailed and burdensome requests EPA included in Part 2 of the ICR is the requirement for actual measurements of tank and separator feed material composition. The issue here is whether this information would meaningfully add to EPA's understanding of oil and natural gas production operations. We believe it would not.

Feed material composition analysis (flash gas analysis) is unnecessary and should not be included in the ICR. EPA has flash gas composition data at its disposal through Subpart W reporting at the sub-basin level. This data could easily satisfy EPA's needs for understanding representative trends in flash gas composition across the industry. Indeed, it is unclear how surveying 3,000 additional facilities under Part 2 would substantially improve EPA's existing dataset, but the data collection itself would be highly problematic for operators.

Should EPA decide to move forward with this request despite its overall lack of utility for the ICR, it should be modified significantly. EPA's selected method for direct measurement of feed material composition for storage tank flash gas analysis, known as the CARB method, is overly prescriptive and not suitable for use in this ICR. This issue is addressed more fully in other submitted comments.

b. General Well Information

We are also concerned by several requirements for general well information requested in Part 2. Among the data requested for well sites are well casing inside diameter, well tubing inside diameter, wellbore length, and well configuration. It is unclear what benefit this information provides to EPA, and based on our analysis, it does not appear to substantively enhance EPA's ability to understand facility design or emissions.

Therefore, we recommend EPA remove these extraneous data requirements from the ICR unless it can justify their benefits. We are concerned that EPA may be incorrectly assuming this data will allow for well blowdown emission calculations. If this is the case, we urge EPA to consider that well casing, well tubing, and wellbore length data are unsuitable for calculating well blowdown emissions because there are numerous other factors that can impact emissions.

Information like well depth and well bore length may not be straightforward to obtain. For example, wells may have multilateral designs like tree roots. Others wells may have capillary strings to allow production from multiple zones but not comingle the oil, natural gas, and water from each zone. For capillary string wells, the same well can produce to multiple separators connected to their own tank batteries, with multiple facilities receiving fluids from a single well. While some of the requests in this section may be suitable for single well bores, they can pose problems for other configurations.

Furthermore, for older producing wells, much of the data requested in this section may be non-existent. It is possible to find wells that have been producing for 50 years or longer using the original well completion. It would be very difficult to find data about well casing diameter, well tubing diameter, and produced gas composition from the first 30 days of production for these older wells.

Where available, much of the data requested by EPA here can be found with state land authorities. For example both Texas and Oklahoma have detailed records that contain much of the information requested here by EPA. Since EPA is obligated to reduce information collection burdens under the Paperwork Reduction Act, we urge EPA to review the appropriate state records rather than place the burden on industry to gather information already reported elsewhere.

For production facilities, EPA requests the quantity of natural gas extracted from all wells. For oil wells, that number can be estimated, but it is important EPA recognize it is a calculation. It is not possible to directly measure associated gas produced at the wellhead. Associated gas that is not sold is most likely directed to a control device from multiple points in the separation process. It is not industry practice to meter gas directed to a control device for many technical reasons, so operators will often use a GOR value to calculate total gas production. GOR values may have been estimated at initial production, but GOR values may change over time as oil production declines. We are concerned that EPA will take this associated gas production data as absolute and make unjustified decisions from the data.

It is unnecessary for EPA to request the volume of oil produced and oil sold from a well. In the oil and natural gas industry, those values are synonymous. This request requires operators to know exactly how much oil is in storage from a previous year's production and how much oil is in storage at the end of the year that was produced, but not yet sold. This is an overly burdensome exercise with no benefit when estimating emissions. We recommend EPA strike the request for quantity of all hydrocarbon liquids leaving the facility (sales).

c. Land Owned or Leased

In Part 2 of the request, EPA seeks information on whether the land is leased or owned. This request will require a great deal of effort by operators to research land files to make this determination with no emission estimation benefit. If EPA requires this information, it must make it clear what value this information will provide to justify the time and expense for this determination.

d. Current Environmental Regulations That Apply

For clarity, scope, and brevity, we recommend that EPA specify that this request for applicable state rules applies to air quality regulations only. EPA should include in this an option to write in other applicable requirements such as Tribal Federal Implementation Plan (FIP) regulations or requirements from a federal Consent Decree. However, it is inappropriate for EPA to use this effort to gather information on, for example, noise ordinances, road traffic requirements, or stormwater permitting.

e. Well Completion and Workover Information

As with much of the general well information, well completion data requested could likely be readily obtained through the appropriate state records. We encourage EPA to work with states to gather its desired well completion information.

In addition to well completion data, EPA is also seeking data on the anticipated date of the next workover. However, gathering this type of information requires clairvoyance on the part of operators to predict changing reservoir conditions, market conditions, availability of equipment, and availability of capital, among other factors. Well workovers are decided on a case-by-case basis, and information about workovers from one well in a specific field could not necessarily be applied to another well even in the same field.

Information on the date of last workover may not always be available either, particularly as oil and natural gas assets are sold regularly, sometimes changing ownership five or more times over the lifetime of a producing well. EPA likely will be able to find the date of last workover in its GHGRP data, when such data is available. However, availability of records on these older facilities can sometimes be problematic, and therefore this type of information may not be available. We recommend that EPA remove next anticipated workover and date of last workover from the ICR or, where possible, to leverage the GHGRP data already at its disposal.

There have been some indications that EPA perceives a workover as a refracturing activity. Consequently, it may be seeking this information with the mistaken belief that a workover constitutes a modification under the Subpart OOOO and Subpart OOOOa regulations and that this information would indicate that the existing facility would become subject to those requirements after the workover. However, a workover is not a refracturing action.

f. Control Device Cost Data

While we appreciate EPA seeking cost data as a part of its request, we are concerned that the information requested may not be available to operators or useful to EPA. For example, the historical costs of control devices are largely irrelevant for the purposes of evaluating the cost of new control devices on existing facilities. Using historical costs to make assumptions about current or future costs is not an appropriate comparison. Many new control devices, such as vapor recovery units (VRUs), have improved significantly in terms of their design but have also increased in cost. For example, current VRUs come with variable motors which are more effective but also more expensive. Older VRUs will not reflect those increased costs. At the same time, other control devices may have decreased in cost over time. Consequently, historical data may not reflect current economics. Instead of focusing on historical data, we encourage EPA to focus on current control device costs.

Additionally, cost data is not necessarily useful for making basin-to-basin comparisons. A control device that may cost $30,000 with installation in one area, may cost $50,000 in another area due to significant differences in the availability (or lack thereof) of roustabout crews, manpower, equipment needed for the installation, etc. As a result, cost data cannot be reliably compared across different basins and states. In some cases, a control device may be moved from one field to another because there happens to be one available. This will drive down cost, but having an extra control device available is unlikely to be planned, and it is impractical to assume control devices are readily lying around.

As with many other elements of the ICR, asset sales and trades will complicate the collection of control device cost data. Operators who own assets that have changed hands one or multiple times may not have access to data about what previous operators spent on control technology.

Similarly, without proper context around whether a control device was added as a retrofit or part of new construction, or the approximate date of when controls were installed, it is difficult to make any useful conclusions about this cost data. This is yet another reason why the focus on historical data is inappropriate.

EPA should also be aware that economic impacts on a well are often considered on a well-by-well basis. A high producing well may withstand a $25,000 control equipment upgrade cost; however, a low producing well may not. In this case, an operator may choose to plug and abandon the well rather than incur the additional cost, greatly adding to the cost to control for that particular well. In addition, the economic impact analysis fluctuates with commodity prices and localized price differentials to benchmark commodity prices.

g. Pneumatic Controllers

In its current form, the pneumatic controller survey is inappropriately scoped and should be modified. To begin, the survey should collect pneumatic controller data on high-bleed, low-bleed, and intermittent-bleed devices only. Counting pneumatic controllers by actuation type will be difficult, as many field personnel conducting this portion of the ICR may not have been trained to identify the pneumatic controller types according to EPA's categories. Instead, it will take pneumatic controller experts to collect and review this information, which further adds to the cost burden and feasibility challenges of this request, particularly in light of EPA's unreasonable 120-day timeframe. EPA's request for rotary vane isolation valve actuators, snap-acting vs. throttling intermittent-bleed controllers, and turbine operated isolation valve operators will not meaningfully improve the quality of EPA's data despite adding substantial burden for respondents.

Furthermore, collecting detailed emission information for intermittent vent pneumatic controllers will not be useful because their emissions are highly dependent on operational conditions. It would be inappropriate for EPA to use the Part 2 request to draw industry-wide conclusions about hundreds of thousands of pneumatic controllers. These devices are purpose-built for individual facilities, and it is inappropriate to assume that actuation rates on one facility's controllers are representative of industry operations. This variability is further compounded by the fact that pneumatic controllers will often actuate at different rates seasonally. Therefore, the high-, intermittent-, and low-bleed classifications will give EPA sufficient understanding of pneumatic controller populations.

We also suggest EPA simplify its information request for instrument air pneumatic controllers, electronic controllers, or mechanical controllers. If facilities are able to use instrument air, they will generally do so for all controllers. Therefore it is unnecessary to gather additional information on actuation rates, snap acting versus throttling controllers, etc. for these devices.

We recommend EPA add a section to the Part 2 Pneumatics section to allow operators the ability to designate whether a pump, valve or controller is controlled by a control device. To be consistent with Subpart OOOOa or industry best practices, operators often vent these devices to a control device or re-capture the gas.

Lastly, we support section 3 information collection on work practices and malfunctions, as this will provide EPA with useful context for evaluating work practice standards.

h. Equipment Leak Information

We are also concerned that EPA has drastically underestimated both the difficulty and the cost of collecting the equipment leak information required under Part 2 of the ICR. As EPA is aware, it currently allows one year of implementation for an LDAR program under its recently finalized Subpart OOOOa. Yet, despite the fact that the proposed equipment leak ICR requirements are more complex, including the time-consuming task of supplying actual component counts, EPA is only allowing 120 days for operators to complete this task.

We question the practical utility of requiring actual component counts. The GHGRP provides fugitive component estimates based on numbers and types of equipment at the facility, in lieu of exact component counts, and the recently finalized Subpart OOOOa LDAR requirements deleted the proposed requirement to take component counts in order to calculate percentage of leaking components. As a result, no EPA programs require exact component counts. Therefore, the vast majority of operators will need to create a reporting process. This includes possibly hiring and training contractors. Completing this ICR will require redeploying personnel and it appears EPA has not accounted for these costs anywhere in its analysis.

Exact counts to this granularity have no added value when analyzing existing oil and natural gas production operations across the country. Such burdensome reporting will not help EPA to understand this industry better in order to develop future regulation of oil and natural gas air emissions.

We strongly recommend EPA allow estimated component counts to decrease the time and cost burden on respondents for a requirement that has limited practical utility. If the EPA finalizes actual component counts, EPA must re-evaluate its costs and time burden estimates here and ultimately allow extra time for respondents to complete equipment leak survey work.

With regard to the questions requiring "Total Number of Components Found Leaking", this information may not be available. Since the compliance period has not begun for the LDAR program under Subpart OOOOa for which detailed records will be meticulously kept, prior efforts to find and address leaking equipment took place promptly, with the leaks fixed right away or tagged and fixed as soon as possible. However, companies would not have maintained records for LDAR at all sites visited.

i. Produced Gas Composition

In the Part 2 request, EPA requests produced gas composition from three different time periods. EPA should consider first asking if operators have a produced gas composition for each well. In some cases, operators may not have the gas analyses from the periods being requested by EPA. It is not possible to retroactively collect this information; operators that do not have historic gas analysis should be exempted from this requirement. This may be particularly problematic for facilities that have been sold one or more times, as the current operator may not have access to that historic data.

In oil plays, operators often do not acquire extended gas analyses. Assuming operators will have a produced gas analysis for each of the three time periods is false. If a produced gas analysis is required for other regulating agencies, it is often an analysis that quantifies C1 – C6 hydrocarbons and provides a C6+ number which air quality regulating agencies would not allow for estimating emissions.

Operators do not anticipate significant changes in produced gas composition over time. We recommend EPA ask first if an extended gas analysis has been performed from a particular well. If so, then an operator can provide that analysis.

j. Gas to Oil Ratio

In the Part 2 request, EPA requests a GOR value from three different time periods. However, a GOR value often is determined during initial flowback, and GOR values after that time period may be difficult to verify. As stated earlier, it is not industry practice to measure gas volumes sent to control devices. Without this verified volume, GOR values are determined by calculation rather than direct measurement. In an oil play, gas is often broken out in a 2-phase separator at a high pressure and again in a 3-phase separator at a lower pressure. While the majority of the gas breaks out in the 2-phase separator, small bumps in pipeline pressures of short duration can cause the gas from the 3-phase separator to be directed to the flare. As a result, casinghead gas is directed to both the sales gas line and the flare. In these situations, the flared volume cannot be verified. Operators can look to gas sales data during times when they anticipate that all gas is sold; however, this cannot be verified with absolute certainty. We recommend that EPA designate a method based on technical feasibility for determining GOR after flowback or change the verbiage to indicate an "estimated" GOR value for periods after the first 30 days of production.

k. Tanks Separators

The Part 2 request contains a worksheet titled Tanks Separators. This is a confusing term not used in the oil and natural gas industry. We ask EPA to clarify if this is referring to Separation Equipment. This worksheet also contains several requests for information regarding continuous monitoring. EPA should be aware that there will be no gaseous flow rate or liquid feed flow rate monitoring on the inlet to a separator as gas and that liquids cannot be individually measured when multiple phases are encountered. Liquid level in a separator vessel also has no bearing on any emission estimates that we are aware of, and those levels often vary continuously depending on how the equipment functions. We recommend EPA strike the request for flow rate monitoring to separation equipment and the request for liquid levels in a separator because it is irrelevant for the purpose of understanding industry emissions.

l. Blowdown

EPA is also requesting a variety of information regarding blowdown of equipment in the "Blowdown" worksheet. While most operators will likely certify that blowdowns occurred at some time during 2015, that may be the only information known. We are unaware of any state or federal regulations requiring oil and natural gas operators to keep records of blowdown events or cumulative volumes for oil wells. As a result, operators may or may not keep such records. EPA should ask whether operators keep records of blowdown events for the various equipment types. If the answer is "yes", then the additionally requested information should switch from black to a cleared cell where the information can be provided.

m. Control Device

Part 2 also contains a request for information regarding control devices in the "Control Device" worksheet. In this worksheet, EPA requests "Typical NG Flow to Device". EPA should define what "typical" means. We recommend revising this request to be average flow rate over the last 30 days.

This section also contains a request for the "Fraction of time control device is operated while NG flow is present". This is an inappropriate request because operators may not be able to continuously monitor the flow of natural gas to a control device. We recommend EPA revise the request to "Fraction of time control device is operated and the well is producing".

3. Definitions

In our review of the proposed ICR's definitions section, we are concerned by the lack of consistency between both Part 1 and Part 2 definitions, as well as the ICR's inconsistencies with other regulatory text definitions. We suggest the following changes to clarify the proposed ICR's definitions:

a. Part 1

Storage Tank and Vessel are used interchangeably, which could create confusion. We suggest instead using "tank" for storage equipment (e.g., storage tank) and "vessel" reserved for process equipment (e.g., separator).

Crude oil includes "drip gases" in its definition. We ask that EPA clarify whether drip gas is a reference to condensate. If so, it should be removed from the crude oil definition because condensate is defined separately.

The current definition of a facility is unclear and could be a source of confusion. For instance, if an operator has a compressor for boosting pipeline pressure and a tank battery on the same location that does not sell to the pipeline, it is unclear if EPA would consider this one or two distinct locations.

It is unclear if Gas-to-oil Ratio (GOR) is the same GOR that an operator would obtain from a flash analysis after a separator. We suggest EPA clarify this definition to "the ratio of the amount of hydrocarbon gas that is generated by the decrease in pressure or increase in temperature to standard conditions to the amount of hydrocarbon liquid that remains after the gas has been liberated", which more accurately describes the necessary change in pressure and temperature.

API Well ID and US Well ID are listed twice, despite seemingly being the same thing. We suggest EPA combine these definitions to avoid confusion.

b. Part 2

Storage Tank and Vessel definition should be amended as suggested in our Part 1 definition comments:

Separator should clarify whether it includes gunbarrel tanks since their primary purpose is to separate water from oil and not gas from liquids.

Heater treater definition should be changed to read "process vessel" instead of "storage vessel" as heater treaters are not storage vessels.

Oil Well/Oil Reservoir and Gas Well/Gas Reservoir definitions are unnecessary for the ICR workbooks and will simply create confusion. EPA has added a gas to oil production threshold of 100,000 scf/bbl to determine reservoir status. However, it does not appear to apply the definition anywhere in the workbook. The closest question about a well or reservoir type is the "Sub-basin Formation Type" question on the "well sites" tab in Part 2 of the request. Even then, the responses are from Subpart W (oil, high permeability gas, shale gas, coal seam, and other tight reservoir rock). Having the EPA define a term regulated by another authority will create confusion and could lead to mismatched regulatory filings and air registrations. If EPA decides to keep the definition, we suggest it consolidate the "gas well" and "oil well" into "well type" and define it as "The type of well as defined or registered with the respective state or land agency." The gas to oil production threshold used in both well and reservoir definitions will not be indicative of the well type, as it could be affected by a variety of factors like gas pockets in an oil reservoir. Further confusing matters, different states have different thresholds when assigning well types. For example, Oklahoma sets the threshold at 150,000 scf/bbl, and Louisiana sets the threshold at 2,000 scf/bbl.

The definition of facility should be revised as suggested in our Part 1 definition comments.

The definition of gas-oil-ratio should be changed to be consistent with the Part 1 definition.

Pressure Vessels should be defined as any vessel that operates under pressure and not atmospheric pressure. EPA's current definition does not reflect this and will create confusion.

4. Recipients

The EPA ICR is flawed because it appears to contemplate collecting information on wells from both owners and operators in connection with the Part 2 survey. Normally, multiple working-interest owners participate in any given well in the United States as non-operating interest owners. Accordingly, requiring both operators and owners to report on the Part 2 survey could result in numerous filings of duplicate information on each well. This would make the data confusing and difficult to aggregate. It would require much more time to process and evaluate accurately. It would also result in unnecessary burdens on the non-operators. The only sensible way to collect the information is to require the operator for each well, as designated and registered by each state oil and gas commission, to report on behalf of all of the owners of the well. EPA should clarify that any party receiving either Part 1 or Part 2 is only required to respond and provide information for wells where it is the operator.

In addition, the EPA estimate in the Supporting Statement that each operator would only be required to report on approximately 30 facilities, including 60 wells, for Part 1 is erroneous. Many oil and natural gas operators operate hundreds and even thousands of wells. The obligation to respond to the Part 2 survey for these companies will be extremely expensive and require huge amounts of time. The ICR must consider that burden and provide adequate additional time for recipients to respond to the ICR.

Part 2 of the ICR will be a significant burden for any operator that receives a request. Yet EPA does not appear to have made any considerations for companies that may receive multiple Part 2 requests. Given that the same employees may be tasked with completing each request, this burden would be compounded on operators that receive multiple Part 2 requests. We strongly recommend EPA develop a methodology to avoid disproportionately burdening a particular operator with an overwhelming number of requests.

Similarly, operators who have received CAA Section 114 requests for information on facility operations and emissions data in North Dakota and elsewhere should be exempted from Part 2 of the ICR. The benefits of this would be two-fold. First, these Section 114 requests are extremely costly and burdensome and have overloaded resources at affected companies. Adding a Part 2 request on top of that would be needlessly burdensome. Second, since these companies have provided voluminous emission and facility data to EPA already, the Part 2 request would be of limited utility for those operators, since EPA now has access to much of this data. Therefore it would be beneficial to both industry and EPA to not needlessly duplicate that work.

Additionally, we are concerned about how EPA will obtain contact information for operators. It is critical that the surveys are directed to individuals in the appropriate role at each company to avoid losing time to complete the surveys. We urge EPA to provide a way for companies to provide the agency with their preferred contact before the surveys are distributed.

We remain convinced that EPA will not be able to collect an appropriately diverse array of information if it chooses to transmit ICR Part 1 and Part 2 simultaneously. As we described previously, there are many factors that define oil and natural gas production. While a GOR approach creates many distinctions, it does not provide – for example – a characterization of conventional or non-conventional production. Yet, this is a significant issue with regard to existing facilities. The overwhelming majority of marginal wells likely will be conventional production. Similarly, most of these wells will be operated by small businesses. Heavy oil production presents a different picture than shale oil production. Enhanced oil recovery operations are another distinct set. For EPA to transmit Part 2 of the ICR without acquiring key information from Part 1 opens a serious question of whether it will be able to meet the statistically significance test of the Paperwork Reduction Act.

Finally, obtaining adequate information under Part 2 for the large marginal well population poses a different challenge than EPA has faced for other components of the oil and natural gas industry. For example, a small refinery still has a reasonably large technical staff, but because a marginal well is typically operated by a small business, its technical staff is far more limited. Similarly, in the current economic climate, these small business operations are also significantly constrained in their ability to absorb the sizeable costs of ICR Part 2. Yet, without adequate input from these operators, EPA will not be able to appropriately determine a regulatory framework. EPA needs to work with the industry to determine an approach that assures it can meet its responsibilities under Section 111.

Conclusions

America's independent oil and natural gas producers fully recognize the importance and responsibility of managing their impact on the environment. We believe that the ICR process can provide EPA with the information it needs to make sound judgments regarding the need for regulation of existing sources of emissions and, if necessary, the information to craft cost-effective regulations. However, those tasks must be based on acquiring accurate and appropriate information from both industry sources and other information sources.

Industry is ready to work with EPA to achieve its objectives, but the current ICR proposal is seriously flawed, inadequate, and inappropriate. As a proposal under the Paperwork Reduction Act, it immediate fails to meet a key requirement of the Act:

> minimize the Federal information collection burden, with particular emphasis on those individuals and entities most adversely affected;

by leaping into a collection approach seeking entity information that can be obtained elsewhere. As we have stated previously, much of the basic information on well location, well construction, well production, even emissions information is available to EPA from sources it already has through DrillingInfo or through publicly available state permits. Before duplicating this information, EPA should first acquire, analyze, and learn about the scope and complexity of the industry – a task in which the industry would be willing participants.

But this ICR proposal does not pursue such a path. Instead, it chooses to drive forward, not based on a sound, rational approach to data collection, but based on having the ICR distributed by October 30, 2016. Further, it envisions submitting both Part 1 and Part 2 simultaneously with 30-day and 120-day response targets. As we previously stated, these time limits are wholly unrealistic for many reasons. First, EPA has seriously underestimated the amount of time – as well as the cost – required to complete its proposed ICR. Second, EPA intends to time the submission of the ICR request when the same industry staff are also tasked with federally mandated compliance actions for its recently released Subpart OOOOa regulations followed closely by development and preparation of Subpart W reports.

We recommended that EPA target a more realistic timeframe – one that would end with Part 2 submissions on June 30, 2017. This realistic schedule would provide for three logical steps. First, it would allow time for EPA to acquire and assess the DrillingInfo and state permit information. Second, it would provide time to send, receive, and analyze the ICR Part 1 and develop an accurate target list for Part 2 to assure that Part 2 would get a statistically significant response that reflects the scope and diversity of the American oil and natural gas production industry. Third, it would give Part 2 participants adequate time to develop the information that would be required.

This Section 111(d) regulatory program will have potentially serious consequences for the future of American oil and natural gas development and production and nationally security if it is done poorly. An arbitrary clock must not drive such a significant regulatory action.

Time is not the only issue that EPA must address. The Paperwork Reduction Act is also intended to assure that costs are considered. EPA has seriously underestimated the cost of its ICR proposal. IPAA members evaluating EPA's requirements have concluded that its cost estimates are understated by factors from 2 to 10 to 100 and more depending on the nature of the request. EPA must recognize these realities and adjust its request accordingly to be within the spirit of the Paperwork Reduction Act. A significant step in this direction would be to utilize its existing information and state permit information this is duplicated in the ICR

In addition, there is a small business challenge here that EPA has yet to recognize and understand. About 70 percent of existing American oil and natural gas wells are marginal wells – low producing wells typically operated by small businesses. EPA must acquire information from these wells to understand the nature of existing sources. Without the information, EPA risks making regulatory decisions that would be catastrophic to the operation of marginal wells without attendant cost-effective environmental benefits. Yet, these small businesses do not have the resources – either staff or finances – to complete the Part 2 ICR as currently drafted.

In these comments, we seek to recommend numerous changes to improve the draft ICR, to present realistic assessments of its time and costs, to raise the complexities that define the American oil and natural gas production industry that EPA needs to understand, and to propose alternative actions that could provide the type of information that EPA needs. Over the past several years, EPA has produced two major regulations on this industry. The first – Subpart OOOO – was conceived in haste because of a court order. The second – Subpart OOOOa – was a political response to Keep It In The Ground environmental activists. Neither had the benefit of sound technical analyses created for the purpose of regulatory development. Now, EPA has the chance to build the underlying information needed for a sound regulatory evaluation. Industry can be a partner in this information development process. Industry wants to be a partner. But so far, EPA is blindly driving an overly burdensome questionnaire process that asks the wrong costly questions because of an arbitrary time schedule. This is not the intent of the Paperwork Reduction Act nor should it be the mandate to the Agency. Time should not be the driver of action. Sound regulation built on sound information should be.

We appreciate the opportunity to submit these comments and participate in the regulatory development process. If there are questions, please contact Lee Fuller at lfuller@ipaa.org or at 202-857-4731.

Sincerely,

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