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## **Evaluation of Existing Regulations**

**Docket ID: EPA-HQ-OA-2017-0190**

May 15, 2017

These comments are filed on behalf of the Independent Petroleum Association of America (IPAA), the American Association of Professional Landmen (AAPL), the American Exploration and Production Council (AXPC), the Association of Energy Service Companies (AESC), the Domestic Energy Producers Alliance (DEPA), 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  
Nebraska Independent Oil & Gas Association  
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 are significantly affected by Environmental Protection Agency (EPA) regulatory actions. Independent producers drill about 90 percent of American oil and gas wells, produce 54 percent of American oil and produce 85 percent of American natural gas.

In addition to the specific comments made herein, we support those comments submitted separately by the participants in these comments.

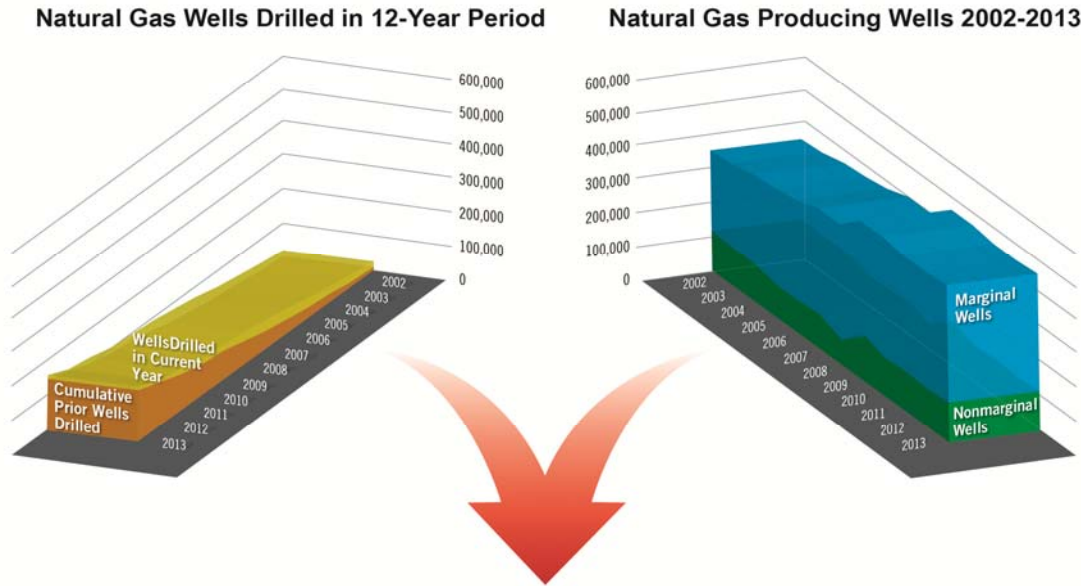
American oil and natural gas producers recognize and support the importance of managing the environment. Overwhelmingly, they live in the communities where they produce. At the same time, oil and natural gas extraction is a primary industry. It involves breaking through layers of hard rock to reach oil and natural gas producing zones. It has over the past decades become more sophisticated through the use of highly technical skills. In particular, the development of horizontal drilling in combination with hydraulic fracturing has opened access to unconventional shale formations and changed the framework of American energy supply. But, it is also an industry with hundreds of thousands of legacy conventional wells. It operates in all types of geographical areas – arid to swamp to offshore, freezing to sweltering, rural to urban. Each of these can create different environmental management challenges.

Independent producers believe that air emissions can be managed, including methane, through cost effective Volatile Organic Compound technologies, that produced water can be used, reused, treated and discharged safely, that drilling fluids will continue to be well controlled. At the heart of these actions are state regulators who understand the differing circumstances under their control and regulate accordingly. Correspondingly, EPA needs to play a distant role that recognizes the expertise and commitment of the state regulators who – like producers – live in these producing areas.

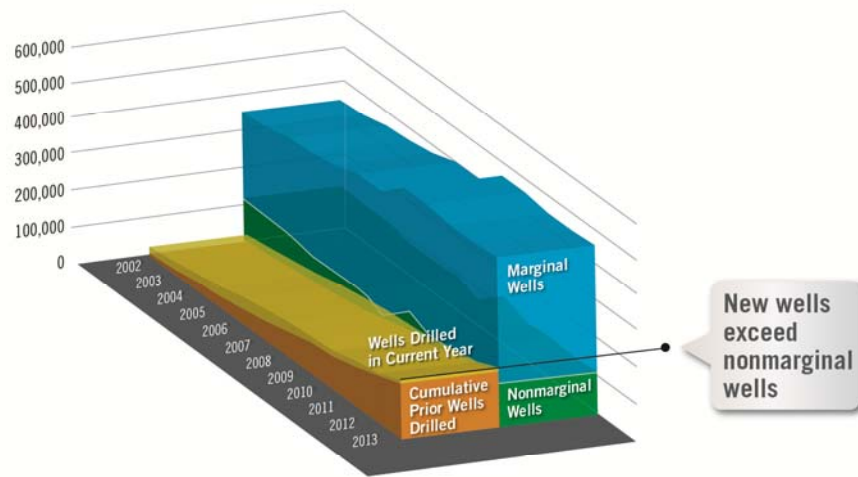
To put these comments in context, it is important to understand the nature of the American oil and natural gas industry. Oil and natural gas wells naturally deplete over time. That is, following high volumes of initial production, volumes begin to decline. Ultimately, the rate of decline slows – typically when the well production reaches marginal well amounts. Correspondingly, the industry is a “food chain” industry. As large companies want more capital,

they sell their lower producing properties to smaller companies. This explains in large measure why small businesses are the primary owners of marginal wells. The following graphic shows how depletion affects the mix of natural gas well operations:

## Natural Gas Wells



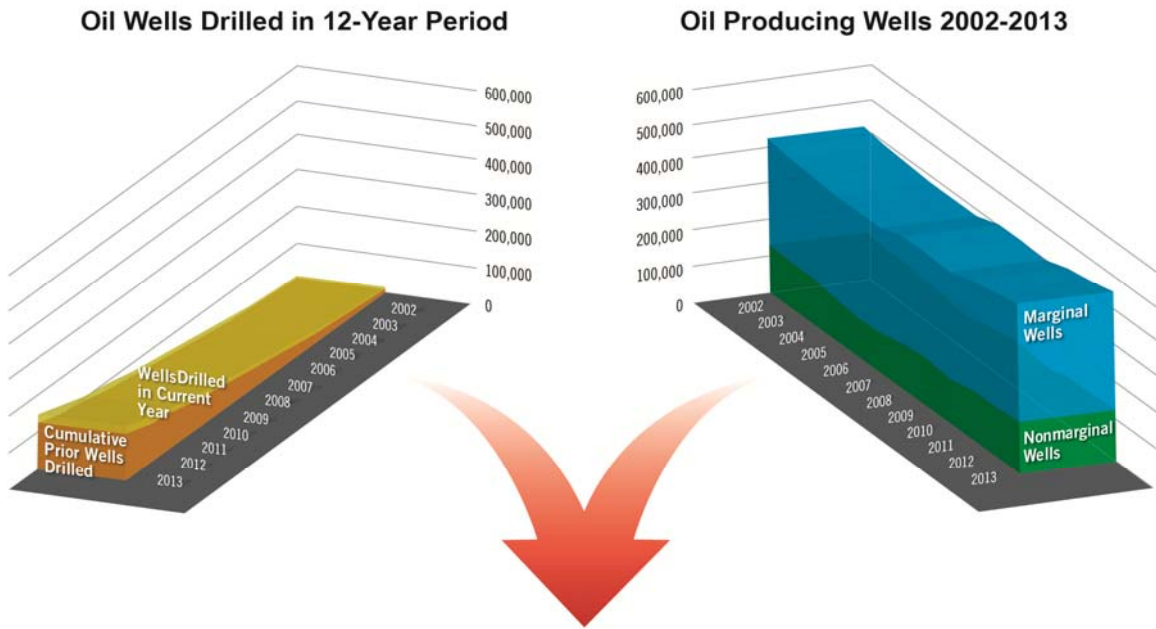
### Natural Gas Well Composition Change — 12-Year Period



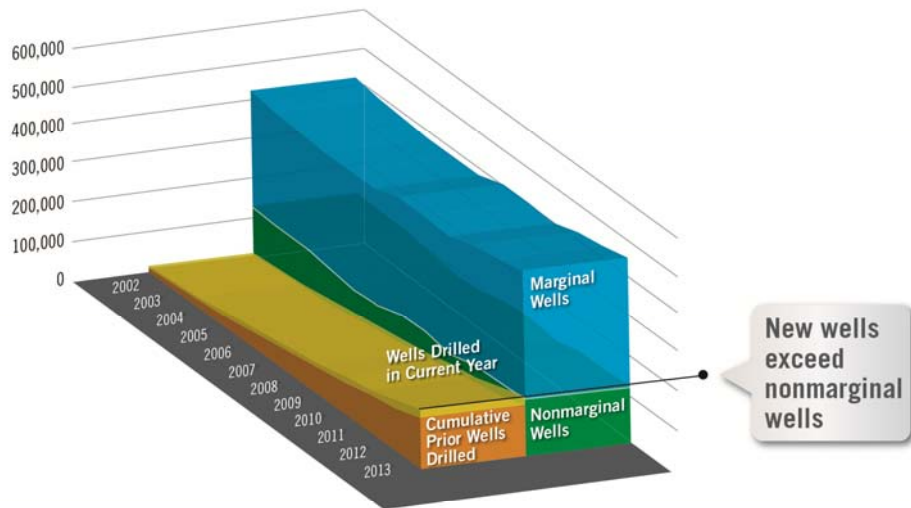
SOURCE: UNITED STATES PETROLEUM STATISTICS, INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

The same dynamics occur for oil wells:

## Oil Wells



### Oil Well Composition Change — 12-Year Period



SOURCE: UNITED STATES PETROLEUM STATISTICS, INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

These comments will address several EPA regulatory actions that can adversely affect independent oil and natural gas producers.

Additionally, these comments will address issues raised in oral comments to the Small Business stakeholder public meeting on April 25, 2017. IPAA is a federally focused trade association. Its membership spans the scope of America's independent oil and natural gas producers. The median size of an IPAA member firm is 12 full time employees. Consequently, IPAA has a strong small business component. The other participants in these comments have similar small business components. These small businesses are the primary operators of America's marginal wells. A marginal oil well produces 15 barrels per day or less; a marginal natural gas well produces 90 mcf/d or less. However, the average marginal oil well produces about 2.7 barrels per day and the average marginal natural gas well produces about 22 mcf/d. Approximately 80 percent of US oil wells are marginal wells. About two-thirds of American natural gas wells are marginal wells. However, collectively they are a significant component of American production generating between 10 and 20 percent of US oil production and between 12 and 13 percent of US natural gas production.

This juxtaposition of small businesses operating marginal wells creates the consequence that EPA regulations that do not recognize their impact on marginal wells result in excessive impacts on these small businesses.

### **Regulatory Framework Objectives**

Independent producers seek a predictable, cost effective regulatory system.

United States environmental regulations are a mix of federal and state regulations. The primary federal environmental laws – the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act and the Resource Conservation and Recovery Act – hinge on balanced federal and state roles. The federal government's role is principally creating national standards, authorizing state management of federal law, stewarding state regulatory actions, addressing interstate and international issues and funding for research and state support. Correspondingly, states develop and manage direct regulatory programs designed to meet national standards and reflect their differing local circumstances. In evaluating its existing regulatory actions, EPA needs to revisit these balances and assure that the states and regulated community are protected against aggressive political efforts to federalize regulations – particularly, from IPAA's perspective, with regard to oil and natural gas production.

More specifically, EPA needs to include a significant state delegation initiative. Most of the actions related to state delegation occurred within the first few years following legislative enactment. Now, decades after the last revisions to these major laws, the state delegation process needs to be rejuvenated; states need encouragement, facilitation and funding. Failure to effectively delegate authority opens opportunities for federal incursion into regulatory activities that are intended to be under state management. And, it places the regulated community in a position where double regulation – state and federal – unnecessarily compounds their daily operations.

For oil and natural gas production, federal regulations should be targeted. For example, federal air emissions regulations should be Volatile Organic Compound (VOC) based. EPA needs to recognize the variability of oil and natural gas production operations and ownership. It needs to

define low production wells and assure that any federal regulation is specifically analyzed for them; these low production wells should be excluded from regulation where that is feasible.

EPA needs to assure that federal technology determinations are based on analyses that are designed for assessing regulations and are scientifically sound. Recent federal regulatory actions have utilized analyses that were never developed for regulatory design purposes. Consequently, EPA extrapolated information to justify its regulatory actions beyond the validity of the underlying data – an issue that is particularly problematic with regard to low production wells. In developing new regulations, EPA needs to devise procedures to use federal resources for analyses – designing programs and assuring data quality and focus for regulation.

EPA needs to thoroughly review and revise its federal enforcement process. It needs to create an enforcement program that treats the regulated community with fairness, respect and dignity. It needs to eliminate the use of excessive threatening tactics, egregious fine proposals and enforcement to compel regulation where EPA has no authority.

## **AIR REGULATIONS**

### **Oil and Natural Gas Production Regulations**

Over the past several years, EPA has created several Clean Air Act (CAA) regulatory actions regarding oil and natural gas production operations. These include: New Source Performance Standards (NSPS) Subpart OOOO and Subpart OOOOa and Control Techniques Guidelines (CTG).

In 2012, EPA promulgated NSPS Subpart OOOO creating VOC regulations on several oil and natural gas production emissions sources – reduced emissions completion (REC) of fractured natural gas wells, pneumatic controllers and storage vessels. In 2016, EPA promulgated NSPS Subpart OOOOa creating methane regulations on additional oil and natural gas production emissions sources – REC for fractured oil wells, pneumatic pumps and fugitive emissions – and converting Subpart OOOO to a methane regulation. In 2016, EPA finalized a CTG for existing sources of oil and natural gas production facilities in Ozone National Ambient Air Quality Standards (NAAQS) nonattainment areas. In 2016, EPA announced its intent to initiate a methane based nationwide existing source regulatory program and started an Information Collection Request (ICR) to collect information for that purpose.

In 2017, EPA terminated the ICR. The Trump Administration announced its intent to revisit the Subparts OOOO and OOOOa regulations and suspended the Subpart OOOOa fugitive emissions requirements pending action on a petition for reconsideration.

This mix of regulations resulted first in the case of Subpart OOOO from a consent decree and subsequently from the Obama Administration Climate Action Plan. Taken together, they present – in their current form – excessive regulatory burdens without attendant environmental benefits. The reasons differ but are primarily related to the shift in the regulatory framework to a methane basis as a pathway to federalizing oil and natural gas production regulation. Importantly, for oil and natural gas production, controlling VOC also controls methane because they are emitted together and, therefore, reduced together.

When the VOC Subpart OOOO regulations were finalized, they were largely based on technology that had been utilized as in EPA's voluntary Gas STAR program. This voluntary

program was highly effective in reducing emissions long before the regulations were created because many of the new large fractured natural gas wells were using these technologies. Nevertheless, as EPA moved from a voluntary program to regulations, it created adverse consequences because in defining terms it captured operations that were not appropriate for the technology and it created opportunities for abusive enforcement actions.

These issues were dramatically expanded when Subpart OOOOa was finalized. First, shifting the regulation target to methane did not improve emissions reductions from new sources, but it did open a little used CAA pathway – Section 111(d) – to create nationwide existing source regulations. The approach would principally target older wells since more recent ones either used Gas STAR voluntary technologies or are permitted under Subpart OOOO. Most of these older wells will be low production wells.

Second, the fugitive emissions component of Subpart OOOOa goes well beyond widely accepted technology. NSPS regulations should be based on the best system of emissions reductions (BSER) “...which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated.” The evolution of fugitive emissions regulations for oil and natural gas production is recent. Emissions analyses in the past several years identified that production emissions are characterized by a few pieces of equipment with large emissions (“fat tails”) rather than a broad array of sources. States have been developing fugitive emissions programs in recent years. None of these use the approach in the Subpart OOOOa regulations. Consequently, it is illogical to suggest that the Subpart OOOOa requirements conform to the BSER standard.

Third, a particular problem with the fugitive emissions regulations relates to their cost effectiveness – a BSER issue – over the life of the facility. While other components of Subparts OOOO and OOOOa are capital mandates – specific equipment being required – the fugitive emissions provisions are enduring operating costs that apply for the life of the well. Consequently, as well production declines, the cost effectiveness of the fugitive emission program changes and becomes more and more burdensome. The initial Subpart OOOOa proposal would have excluded low production wells from the requirements, but this exclusion was eliminated in the final regulation based on a specious analysis from Keep It in the Ground environmental activists.

The CAA provides for the development of CTG for existing sources of criteria pollutants in nonattainment areas. One of the most common uses relates to Ozone NAAQS nonattainment areas where the targeted criteria pollutants are VOC and/or nitrogen oxides. While EPA was in the process of proposing Subpart OOOOa and initiating its drive for a nationwide methane existing source regulations, it also proposed VOC CTG for existing oil and natural gas production operations in ozone nonattainment areas.

VOC CTG apply in Moderate, Serious, Severe and Extreme ozone nonattainment areas. State Implementation Plans (SIPs) must include regulations that have been published as CTG as a part of their Reasonably Available Control Measures (RACM) or they have to develop alternative regulations to obtain the predicted VOC reductions from the CTG. While the CAA provides for minimum source sizes that must be regulated in these Ozone nonattainment areas – ranging from

100 tons/year to 10 tons/year depending on the classification – these source size limits do not apply when a CTG regulates smaller facilities.

Moreover, the oil and natural gas production CTG is essentially a regulatory mix that applies the NSPS technologies to existing sources. However, those BSER requirements are based on their application to new or modified facilities. The technology standard for CTG – which are required for existing facilities – is Reasonably Available Control Technology (RACT). BSER and RACT are not the same; RACT must consider the cost effectiveness of its technologies in retrofitting existing sources. The CTG as finalized essentially require replacing existing equipment. EPA’s development of the CTG should have been primarily analyzing its impact on low production operations. As earlier graphics showed, after about a decade, wells drilled during that decade will be all of the non-low production wells. This means that they will be comprised of the NSPS technology requirements – in this case, pneumatic controllers and storage vessel controls. Consequently, the predominant cost burden of the CTG will be borne by the legacy wells that are the small producers. Yet, EPA made no effort to assess RACT between these clearly different components of the array of producers and to assess the cost effectiveness of that assessment.

Both the BSER determination in Subparts OOOO and OOOOa and the RACT decisions in the CTG development raise significant questions about the nature of EPA’s technology evaluations. The CAA tasks EPA with the responsibility to make critical, long lasting decisions regarding technologies that have extensive national implications. BSER becomes the national standard for new sources – requirements that must be met on every new and modified source. RACT becomes a mandate that states must implement in nonattainment areas or obtain comparable reductions from other sources – a politically unlikely result.

If the experience in these regulations is a fair indicator, EPA faces an enormous challenge to assure that it properly acquires and assesses technology. While EPA lists many studies in its justification of both the Subpart OOOO and OOOOa regulations and the CTG, these studies fall well short of the materials that are needed for regulatory development. Realistically, the better studies were broadly designed to merely understand the nature of oil and natural gas production emissions. They have been useful in establishing that the emissions patterns for these operations are characterized by a few “fat tails” – failed or poorly maintained equipment – rather than broad systemic losses. But, they were never crafted to be used for regulatory development. Nevertheless, EPA has used them for that purpose. In Subpart OOOO, the failure of this approach was largely suppressed because the NSPS technologies were ones that were in use in the EPA Gas STAR voluntary program. But, their use in Subpart OOOOa for the fugitive emissions component is illustrative.

The regulation of fugitive emissions primarily relies on an excessively costly optical gas imaging (OGI) leak detection and repair (LDAR) program. The LDAR requirements were wholly inappropriate. NSPS is intended to use a nationally applicable, adequately demonstrated BSER. Multiple states have been creating fugitive emissions programs. All are different; none use the approach in Subpart OOOOa. EPA’s drive to embrace its program based on the paltry analytical information it had falls well short of a BSER determination.

Compounding the lack of sound, federally sanctioned studies, EPA also chose to rely on wholly flawed, advocacy studies in its actions. When EPA proposed its LDAR program, it created an exclusion for low producing – marginal – wells. Importantly, producers do not intentionally drill



marginal wells, but all wells eventually decline and become marginal. By creating the low producing well exclusion, small businesses would not have been subjected the demanding costs of LDAR. However, in the final rule, EPA removed the low producing well exclusion. Sadly, this is the precise intent of the Keep It in the Ground environmental movement that dominated the EPA decision to remove the low producing well exclusion. This decision was principally based on a specious study that creates the impression that low producing wells are large emitters. Its flaws are described in Appendix 1.

More broadly, it calls into question whether EPA can fulfill its statutory CAA responsibilities relying on studies that it neither designs nor funds. Clearly, in this instance, the failure to have a well-designed framework of information failed to produce well designed regulations. Given the clear political pressure that was driving the Subpart OOOOa and CTG requirements, EPA failed to stand up to the pressure and insist on sound and robust regulatory studies to meet its responsibilities.

A counterpoint to these concerns occurred on April 26, 2017, when an EPA study was published. The study addressed emissions from pneumatic controllers in oil and natural gas operations. Its significance remains to be seen, but it presents some of the issues described above in an interesting context. At its heart, the study – conducted by EPA experts – concludes that EPA has been overestimating emissions from pneumatic controllers. In fact, EPA researchers found methane emissions from intermittent bleed devices were 97 percent lower than the standard emission factor for intermittent pneumatic control devices EPA uses for estimates in its Greenhouse Gas Inventory (GHGI). This is relevant on a national scale considering EPA’s latest GHGI reported 45 percent of oil and gas system methane emissions in 2015 were attributable to pneumatic controllers. The researchers acknowledge the significance of this finding by noting pneumatic devices are the “most significant sources of CH<sub>4</sub> in ONG<sup>1</sup> production field operations.”

This issue of pneumatic controller emissions has been part of a larger debate regarding EPA’s regulations under the Climate Action Plan. When the Obama Administration initiated its Climate Action Plan regulatory efforts, it argued that new regulations – in this instance Subpart OOOOa and CTG – were needed to meet a 45 percent emissions reduction target for methane from 2012 to 2025. Industry countered that the Subpart OOOO regulations met this target for oil and natural gas production. It was a statement largely borne out by the GHGI reports.

Subsequently, EPA adjusted the GHGI by increasing emissions primarily related to pneumatic controllers. Key to EPA’s rationale was a conclusion that reported data were showing higher emissions – based on EPA emissions factors. And, since only about thirty percent of oil and natural gas operators directly reported, EPA needed to scale up the other emissions in the inventory. Industry objected to this arbitrary scale up because, when EPA set the limits to determine direct reporters, it argued that it would get about 85 percent of emissions from 30 percent of the operators. This was largely valid because roughly 70 percent of the operators would be low producing wells. But, in its scale up, EPA increased the pneumatic controller calculated emissions on the basis of number of operators – or effectively added an amount equal to twice the reported amount.

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<sup>1</sup> ONG – oil and natural gas

The new study should change all of these calculations. And, in doing so, it should demonstrate that the necessity for Subpart OOOOa and the CTG are substantially overstated. Significantly, unlike the unfortunate history of using available but not directly related analyses for the recent EPA regulations, this new report was designed and conducted by EPA.

### *Small Business Implications*

Because Subparts OOOO and OOOOa are NSPS, they are perceived as regulations that would have limited small business implications. They are largely thought to be capital requirements that are applied to new natural gas and oil wells. But, their application is different.

### Subpart OOOO

Subpart OOOO was characterized as a regulation directed at managing hydraulically fractured natural gas wells. This was only true in part – its application to REC. However, even then, the scope of its definitions was broader. While the concept of REC – or green completions – and the framework of the regulations were based on water based hydraulically fractured wells with long horizontal legs developing shale formations, the regulation language captured other types of wells.

One key example is nitrogen fractured vertical wells. Instead of using water as the fracturing media, these wells use nitrogen. However, the REC process is predicated on getting produced gas into pipelines quickly to prevent emissions. This concept works well for water fractured wells because gas-water separation is straightforward. It does not work for nitrogen fracturing because a gas-nitrogen stream cannot be readily separated. This issue has a specific small business consequence. Nitrogen fracturing is not used for large gas wells with horizontal legs. It is used for small vertical wells in limited formations; these wells are developed by small business operators. EPA should have used greater efforts to assure that its scope was appropriate for the technology it required. Clearly, in this instance, it missed. Equally clearly, in the five years since the Subpart OOOO regulations were finalized, EPA has been unwilling to straightforwardly address its failure. Rather, it has tried to maneuver around the edges using the concept of changing the definition of low pressure wells. It is a strained and ineffective path. EPA needs to simply remove nitrogen fractured wells from the scope of Subpart OOOO.

Another aspect of the Subpart OOOO REC requirements that affects small business relates to EPA's failure to distinguish between unconventional and conventional formations in the scope of Subpart OOOO (and Subpart OOOOa when it expanded the REC requirements to oil well completions). The tight formations characterized by the success of America's development of shale gas and shale oil formations are characteristically unconventional formations. However, hydraulic fracturing is also used in the development of conventional formations. While EPA's Subpart OOOO definition would appear to reflect this distinction, when a small business operator developing conventional oil formations in the Illinois Basin sought clarification that its operations were not subject to Subpart OOOOa, it was rebuffed.

### Subpart OOOOa

Subpart OOOOa expanded oil and natural gas production regulations in significant and adverse aspects for small business operators.

A primary aspect of Subpart OOOOa was the decision to change the targeted emissions from VOC to methane. Not only did Subpart OOOOa target methane, it revised the scope of Subpart OOOO. These changes did nothing to improve oil and natural gas production emissions management since VOC and methane are emitted simultaneously and the regulations capture both. It was a political decision because it would open a pathway to regulate existing sources on a national basis. This change is a direct effort to pursue marginal wells and shut them down.

To appreciate the small business impact, it is important to understand that – unlike one time capital requirements for control equipment – the LDAR program creates an enduring operating cost for the life of the well. Because oil and natural gas wells decline, the cost effectiveness of this requirement changes as the costs must be borne by ever smaller production. When EPA deleted the low production well exclusion for its LDAR requirements, it harmed small business producers. First, the long-term value of wells drilled under the NSPS will be less. They will not be economic as long and particularly will not have value to be sold to small businesses. EPA did not include this consequence in its BSER determinations. Second, if EPA develops a nationwide existing source rule with the same framework, the broad fabric of America’s marginal wells (oil and natural gas) will be destroyed.

#### Control Technique Guidelines

The oil and natural gas production CTG adversely affects small business operators because it applies to low producing operations. The justification fails to consider the costs that must be borne by small operators with low producing wells.

#### *Recommendations*

The Trump Administration decision to review the Subpart OOOO and OOOOa regulations can allow for a more thorough understanding of their key components and to make them more cost effective. As a first step, the regulations should be changed for oil and natural gas production to apply to VOC emissions rather than methane. This change would reinstate the basic framework from the 2012 promulgation of Subpart OOOO. It would have little impact on new source emissions reductions of methane since VOC and methane are emitted together and control simultaneously. At the same time, it would eliminate the clearly political decision to create a pathway to nationwide federal regulations of existing sources through rarely used Section 111(d). The primary consequence of applying Section 111(d) to oil and natural gas production facilities is the devastating impact it could have on small business low production wells – an unnecessary consequence that reduces American oil and natural gas production without generating substantial environmental benefits.

Further, the Administration’s decision to stay the effective date of the fugitive emissions program in Subpart OOOOa and open the record to reconsider these requirements should lead to a modification of regulations applying to low producing wells – a modification to reflect the distinct differences in the nature of these wells compared to the large hydraulically fractured wells the NSPS were originally conceived to address.

In fact, EPA should utilize its authority under the CAA to create a subcategory within the Oil and Natural Gas Sector that would apply to low producing oil and natural gas wells. At this time, it should reserve that subcategory for possible future use. Such an action would allow for the

analyses of regulations of these small business operations to be based on their limited emissions and their economics. It would assure that any BSER is applicable to these operations.

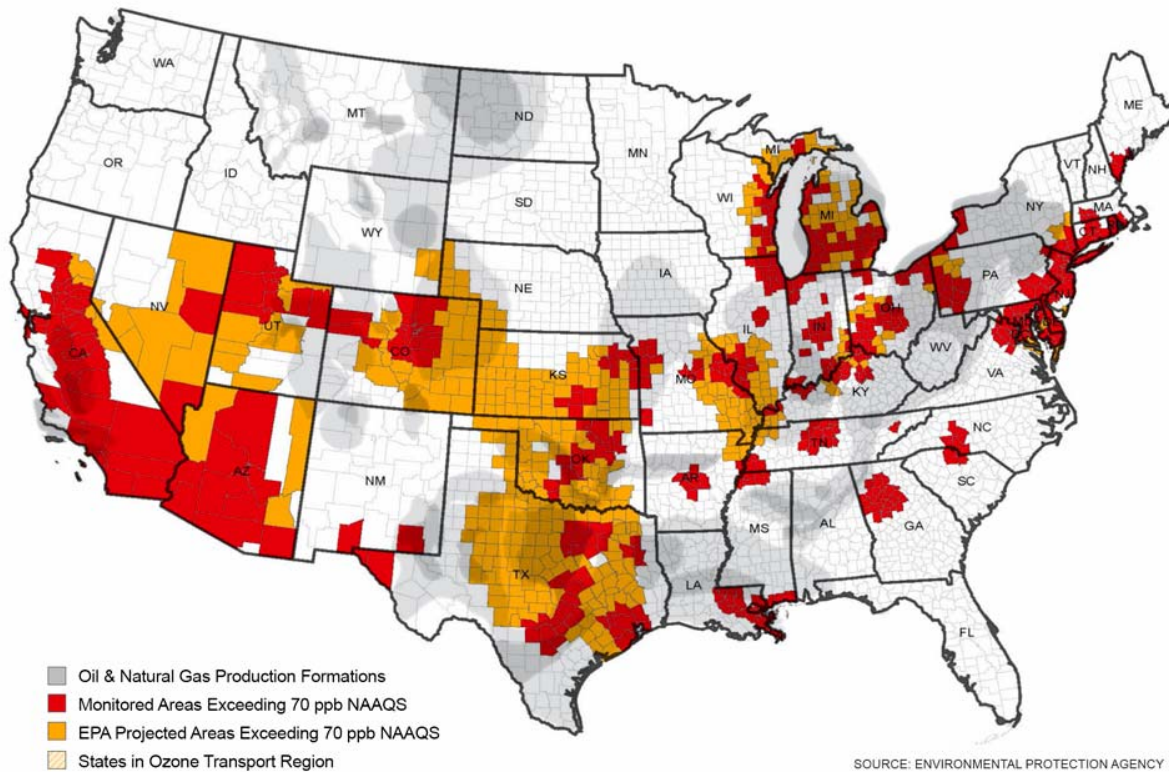
The CTG need to now be considered in the context of the Administration's actions on Subpart OOOOa and OOOO. Because these regulations are positioned to be reconsidered, the CTG need to be addressed accordingly. It should be suspended or withdrawn before it becomes a part of SIP revisions. After judgements are made on Subpart OOOOa and OOOO, the CTG need to be reconsidered and any further action should be based on both an accurate understanding of the emissions from existing sources and a true evaluation of the technology requirements as they apply to existing sources. Additionally, a thorough assessment of the impacts on small businesses must be made. Importantly, any such analysis needs to recognize that the dynamics of oil and natural gas production – as the graphics previously presented show – reflects the inevitable turnover of wells. Consequently, as time passes, the inventory of wells will become populated with those that meet the requirements of the NSPS and the existing wells that would be affected by the CTG will be overwhelmingly low producing, small business owned wells.

EPA needs to revamp its NSPS and CTG processes to assure that it has adequate information on the nature of air emissions and the applicability of regulations to manage those emissions. The recent experiences with Subpart OOOOa and CTG, in particular, indicate that EPA failed in its fundamental statutory duties to identify BSER and RACT technologies. It needs to develop and use studies that are regulatory based – and it needs to have the capability to thoroughly understand and analyze external information that is submitted and is specious.

### **Ozone National Ambient Air Quality Standards (NAAQS)**

EPA should reconsider the 2015 revision to the Ozone NAAQS. The Ozone NAAQS can have a bearing on both the NSPS and CTG requirements for oil and natural gas production. American oil and natural gas operations are located where the resources exist. Unlike manufacturing facilities, they cannot choose where to operate. Historically, much of America's oil and natural gas has been located in largely rural areas. Recent development of American shale resources has placed operations closer to populated areas – many of which are in Ozone nonattainment areas. However, EPA's decision to lower the Ozone NAAQS captures areas that have previously been in attainment. The following map provides a perspective on the interaction between American production areas and nonattainment with the new Ozone NAAQS.

## Ozone Nonattainment Areas Impacting American Oil & Natural Gas Production



While oil and natural gas production facilities have always been subject to RACM in current Ozone nonattainment areas, the CTG changes the regulatory framework significantly. Part D of the CAA provides for states to impose RACM on existing stationary sources as a part of the requirements to demonstrate attainment or Reasonable Further Progress toward attainment. These RACM requirements, however, apply to stationary sources of a specific size depending on whether an Ozone nonattainment area is classified as Moderate, Serious, Severe or Extreme. Therefore, regulation of existing oil and natural gas production facilities depended both on their size and the status of the Ozone nonattainment area. The CTG in general does not set emissions thresholds for its application. As such, for large or small producers, or large or small emitters, the regulatory burden will apply and will apply far more broadly.

Ozone has consistently been the most difficult primary NAAQS for certain areas to meet. The following figures demonstrate the reality of Ozone NAAQS nonattainment. Figure 1 presents EPA's assessment of the areas of the country that fail to meet the 1997 Ozone NAAQS of 84 ppb (8 hour). Figure 2 presents EPA's assessment of the areas of the country that will fail to meet the 2008 Ozone NAAQS of 75 ppb (8 hour) in 2020. Figure 3 presents EPA's assessment of the 2015 Ozone NAAQS by 2025.

Today, 90 percent of those areas meet the 1997 Standards

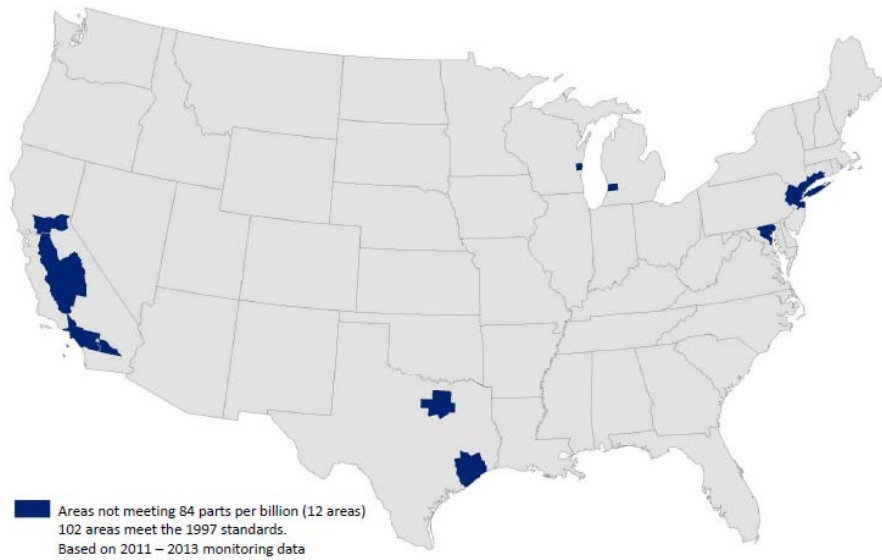


Figure 1

Source: Environmental Protection Agency

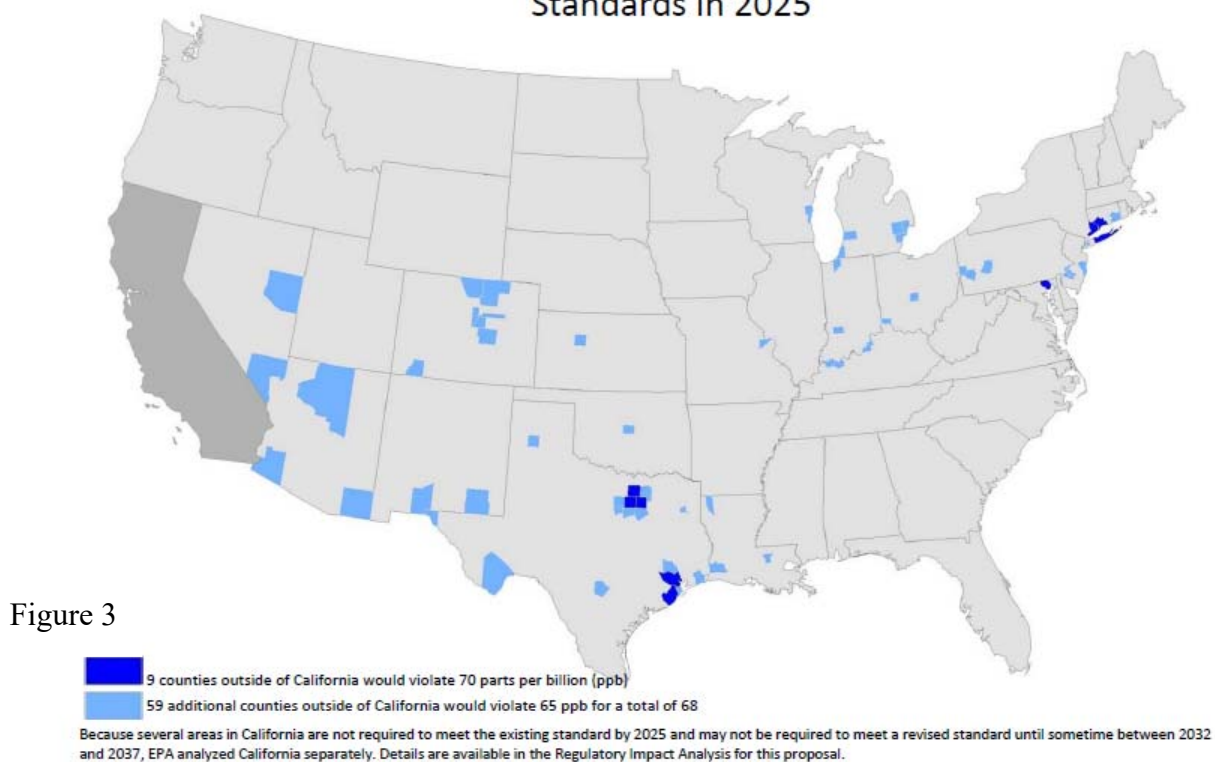
**Counties with Monitors Projected to Violate the 2008 8-Hour Ozone Standard of 0.075 parts per million (ppm) in 2020**



Figure 2

Source: Environmental Protection Agency

## EPA Projects Most Counties Would Meet the Proposed Range of Standards in 2025



Source: Environmental Protection Agency

EPA's analysis shows that there are certain areas of the country that are enduring Ozone NAAQS nonattainment areas – areas that cannot meet any Ozone NAAQS that has been promulgated. The same areas that failed to meet the 1997 Ozone NAAQS and the 2008 Ozone NAAQS also will fail to meet the 2015 NAAQS by 2025 and, realistically, any time until well after 2030. What this means is that EPA's claimed health benefits from the 2015 NAAQS will not occur in these enduring nonattainment areas.

Equally important, the regulatory requirements in these enduring nonattainment areas will be no different under the 2015 NAAQS than they are under the 2008 NAAQS. These areas are subject to regulation under Part D – Plan Requirements for Nonattainment Areas of the CAA.

Part D was created in the 1990 CAA amendments. It creates a series of specific minimum requirements for each area in Ozone NAAQS nonattainment initially based on the area's ozone monitoring values relative to the Ozone NAAQS. Areas are classified as Marginal, Moderate, Serious, Severe and Extreme. Each classification is given a specific time frame in which to attain the Ozone NAAQS. Importantly, if an area fails to meet the NAAQS in its allotted compliance period, it is reclassified to a higher classification, required to implement the mandatory requirements and given an extension of time to meet the NAAQS. Part D requirements were initiated after the 1990 CAA amendments with attainment dates ranging from 1993 to 2010. Even with attainment date extensions, these dates have passed.

The significant impact of Part D is that perpetual nonattainment eventually produces a baseline of regulations and requirements of additional annual percentage reductions. Since these areas have been subject to Part D for 25 years, their future regulatory requirements will be the same iterative percentage reductions under the 2008 NAAQS as the new one. Adopting the 2015 NAAQS will produce the same regulatory requirements for these areas as the 2008 NAAQS.

EPA has stated in its support documents for its 2015 Ozone NAAQS that:

Existing and proposed federal rules . . . will help states meet the proposed standards by making significant strides toward reducing ozone-forming pollution. EPA projections show the vast majority of U.S. counties with monitors would meet the proposed standards by 2025 just with the rules and programs now in place or under way.

Consequently, these national, federal requirements will essentially protect the overwhelming number of areas that would be placed in Ozone NAAQS nonattainment by the 2015 NAAQS without any of the local actions that would be required from such categorization.

For these areas that EPA projects would reach attainment using only national, federal mandates regardless of the NAAQS, promulgating the 2015 NAAQS will compel them to be subject to the requirements of Part D of the CAA. Because Part D imposes a series of minimum requirements, the 2015 NAAQS will impose emission controls on new sources in those areas, including offsets, which will be burdensome, cost ineffective and unnecessary since EPA believes these areas would reach attainment using only its national regulations.

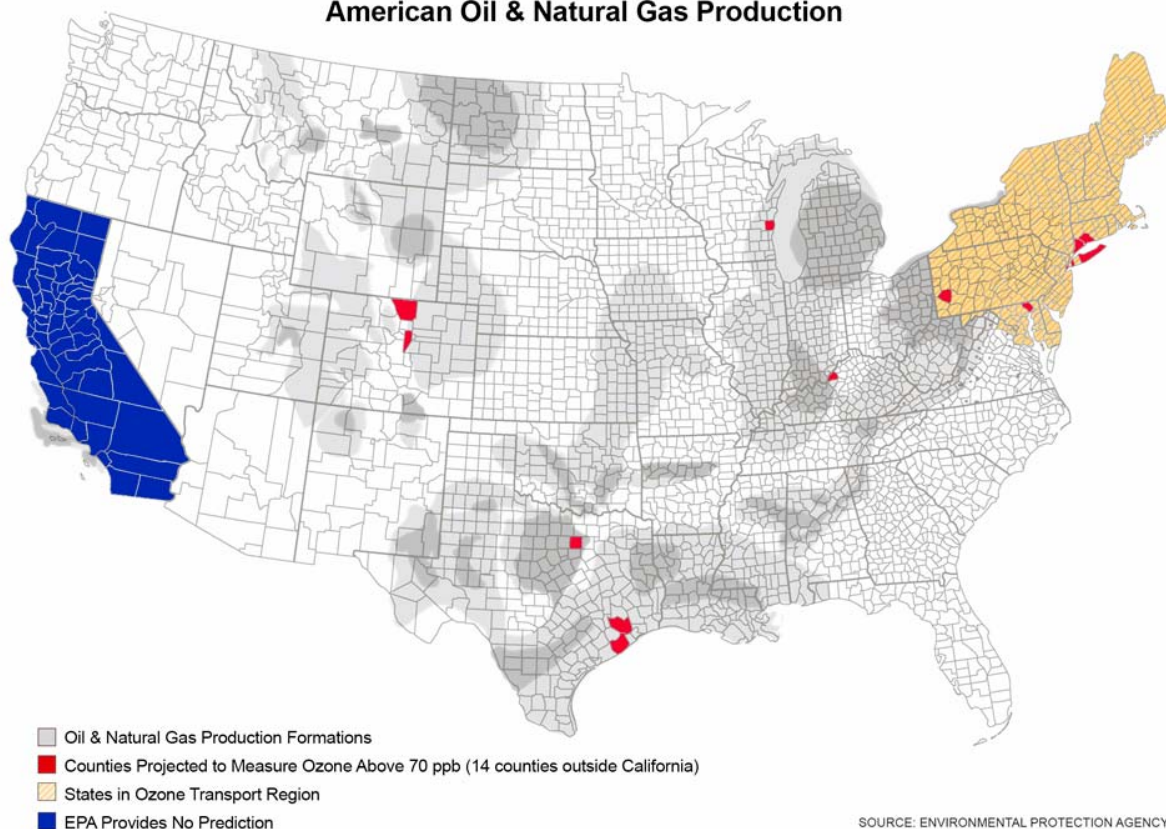
Once an area becomes subject to Part D, minimum requirements are mandated. For example, all new construction must not only comply with rigorous emissions controls, but all remaining emissions must be “offset” by reductions in existing emissions that are not otherwise regulated. Many of the areas that would fall into initial Ozone NAAQS nonattainment but would later attain the NAAQS are largely rural or with smaller municipalities. These areas will likely have limited existing emissions sources to regulate. These areas will face either an effective construction prohibition or the choice of shutting down existing operations that employ current workers.

The oil and natural gas production CTG get pulled into this murky process. Enduring Ozone nonattainment areas already are a possible target for RACM requirements, but those requirements are predicated on the size of the source and therefore not imposed without consideration of their impact on emissions and with localized consideration of cost effectiveness. For the newly captured Ozone nonattainment areas that EPA believes will meet the 2015 Ozone NAAQS using national, federal regulations – an assessment made without the inclusion of the proposed CTG – the application of the proposed CTG is unnecessary to reach attainment. However, because the CTG would be applied and would be applied to such small sources, these reductions are also removed from the possible pool of emissions that could be managed as a part of emissions offsets needed to build new facilities. In many of these areas, new facilities are likely new oil and natural gas wells. Consequently, the impact of the CTG would be to limit new production.

As the following graphic shows, EPA projects that only a few areas will remain in Ozone nonattainment in 2025.



### EPA Projected 2025 Ozone Nonattainment Areas Impacting American Oil & Natural Gas Production



This projection is based on regulatory actions taken without the CTG. It demonstrates that the CTG is not essential to Ozone NAAQS attainment. Certainly, in some enduring nonattainment areas some oil and natural gas production facilities would be subject to RACM, but these decisions would be based on local conditions and the economic circumstances of the oil and natural gas production operations in those areas. The CTG would make all oil and natural gas production operations subject to the CTG without a compelling need – based on EPA’s own projections of Ozone attainment – and without the opportunity to assess local need. Moreover, it would eliminate possible actions that could facilitate new construction as offsets and thereby unnecessarily threaten economic growth in these areas.

#### *Recommendations*

EPA should reconsider the 2015 Ozone NAAQS revision. Given that the enduring Ozone nonattainment areas fail to attain the 2015 NAAQS and would be essentially undertaking the same regulatory program as under the 2008 NAAQS, the health claims for the 2015 NAAQS need to be carefully reviewed. Additionally, if the areas that become nonattainment as a result of a lower NAAQS but would attain it without local controls, there are no additional health benefits in those areas but there would be unnecessary regulatory consequence that should not be compelled on these communities.

## **WATER REGULATIONS**

The Clean Water Act (CWA) can impact American oil and natural gas producers in several ways. The most prominent involve regulations that result from interpretation of Waters of the United States (WOTUS) and Effluent Limitations Guidelines (ELG).

### **Waters of the United States**

Oil and natural gas are found throughout the United States. Significant reserves underlie arid areas. These operations are distant from waterbodies. However, resolving the ongoing deliberations on the scope of the navigable waters definition can have significant consequences.

Most notably, certain elements of the CWA are linked to whether they affect navigable waters. For example, the Spill Prevention, Control and Countermeasures (SPCC) planning requirements are based in part on the amount of oil at a site and in part on whether a potential spill would reach navigable waters. Consequently, a WOTUS definition that reaches well beyond truly navigable waters and adjacent wetlands can subject facilities that would never actually impact them. Yet, the SPCC plan regulations require substantial capital investment for the construction of protective equipment. If the likelihood of a spill affecting navigable waters is miniscule, these requirements are neither cost effective nor environmentally beneficial.

Another significant WOTUS related issue involves CWA Section 404. Here again, the CWA requires dredge and fill permits if navigable waters are affected. All oil and natural gas production facilities require construction of necessary pads for operation. When this construction must take place near waterbodies, the necessity of obtaining a Section 404 permit is understandable. But, when construction occurs in arid topography – far from waterbodies – Section 404 permits are neither necessary nor appropriate.

#### *Small Business Implications*

For small business operators, complying with costly planning and investment requirements that are distant from navigable waters diverts capital from the necessary expenditures to keep wells operating, particularly low producing wells.

#### *Recommendations*

The Trump Administration decision to act on the WOTUS regulations to reflect the Scalia decision in the *Rapanos v. United States* case is a sound first step to pull the scope of CWA jurisdiction back toward Congressional intent in its 1972 CWA legislation. At that time, the context of navigable waters was far clearer than it now appears to be. Then, during Senate and House of Representatives debate on the CWA, the definition relied on a widely understood use of the term “navigable waters”. Only when the CWA was reported by a House-Senate conference committee did the term “waters of the United States” appear. Anyone familiar with the chaos of Congressional debate during the deliberations of a conference report knows that it would not have drawn the attention that it has lastingly produced.

### **Effluent Limitations Guidelines**

Waste water discharges are regulated through the development of ELG. ELG then become the basis for National Pollutant Discharge Elimination System (NPDES) permits by either state or federal permitting agencies. The ELG for direct discharges from oil and natural gas production

facilities was written in 1979. Generally, it prohibits oil and natural gas produced water direct discharges. While this conclusion was arguably not Best Available Control Technology Economically Achievable (BATEA) – the CWA requirement for waste water treatment – even in 1979, it reflected that the widespread use of underground injection of produced water was the preferred option for over 95 percent of produced water volumes at that time. No major review has occurred since, but the industry has changed.

In recent years, EPA turned again to produced water discharges from oil and natural gas production operations. First, it evaluated possible ELG for coal bed methane production but ultimately chose not to pursue it. Then, it turned to shale gas production, largely triggered by issues in Pennsylvania where underground injection options are limited.

EPA created pretreatment standards for discharges of wastewater from onshore unconventional oil and gas (UOG) extraction facilities to municipal sewage treatment plants (also known as publicly owned treatment works, or POTWs). The UOG extraction facilities POTW pretreatment ELG creates two issues that need to be addressed.

First, in defining UOG extraction facilities, EPA missed the mark. While EPA publicly described the scope of its ELG as applying to shale formations considered to be unconventional, its final rule included formations considered as conventional formations that had been developed for decades prior to the advent of shale gas.

Second, and more significant, EPA failed to meet its fundamental mandate to develop ELG based on BATEA. The BATEA concept requires EPA to identify technologies that manage the waste in effluents, determine if the technology is available as a commercial application, and assess whether it is economically achievable. In its UOG extraction facilities pretreatment ELG, EPA identified no technologies and made no economic analysis – though technologies exist. Instead, it merely concluded that it would prohibit discharges to POTWs from UOG extraction facilities. It argued that underground injection and recycling would be available as a management option. But the reality is that underground injection in some states – notably Pennsylvania – is not an option and cannot be assumed to always be available. Similarly, recycling of produced water is an option when drilling activity is high enough to consume the water, but as EPA finalized the ELG, drilling activity and recycling were declining.

We addressed these issues and EPA's positions more extensively in comments filed on the EPA proposal in our comments in July 2015 as follows:

Once EPA initiated the process to develop a pretreatment ELG for UOG extraction waste waters sent to POTWs, it needs to fully assess the potential implications of its actions on current and future management of this waste water.

As EPA states:

EPA develops ELGs that are technology-based regulations for specific categories of dischargers. EPA bases these regulations on the performance of control and treatment technologies. The legislative history of CWA section 304(b), which is the heart of the effluent guidelines program, describes the need to press toward higher levels of control through research and development of new processes, modifications, replacement of obsolete plants and

processes, and other improvements in technology, taking in to account the cost of controls. Congress has also stated that EPA need not consider water quality impacts on individual water bodies as the guidelines are developed....

There are four types of standards applicable to direct dischargers (facilities that discharge directly to surface waters), and two types of standards applicable to indirect dischargers (facilities that discharge to POTWs), described in detail below.

More specifically, in describing Pretreatment Standards for Existing Sources (PSES) and New Sources (PSNS), EPA states:

...section 307(b) of the Act calls for EPA to issue pretreatment standards for discharges of pollutants from existing sources to POTWs. Section 307(c) of the Act calls for EPA to promulgate pretreatment standards for new sources (PSNS). Both standards are designed to prevent the discharge of pollutants that pass through, interfere with, or are otherwise incompatible with the operation of POTWs. Categorical pretreatment standards for existing sources are technology-based and are analogous to BPT and BAT effluent limitations guidelines, and thus the Agency typically considers the same factors in promulgating PSES as it considers in promulgating BAT. ... Similarly, in establishing pretreatment standards for new sources, the Agency typically considers the same factors in promulgating PSNS as it considers in promulgating NSPS (BADCT)<sup>2</sup>.

These statements clearly envision a process that assesses technology designed to meet specific standards whether they are Best Practicable Technology (BPT) or Best Available Technology (BAT) or BADCT. These concepts include analyses of the technologies that can be applied to the waste water being addressed, evaluating the reductions achieved and the costs. But, EPA did not undertake such a robust analysis in this case. Rather, as EPA states:

EPA does not propose an option with numerical discharge pretreatment requirements prior to discharge to a POTW for the following reasons. First, the existing requirements for direct discharges of UOG extraction wastewater in the Onshore Subcategory require no discharge of pollutants. As explained above, EPA generally establishes requirements for direct and indirect discharges so that the wastewater receives comparable treatment prior to discharge to waters of the U.S.

Second, the option EPA proposes, zero discharge of pollutants in UOG extraction wastewater to POTWs, is widely available, economically achievable and has no incremental (and, therefore,

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<sup>2</sup> Best Available Demonstrated Control Technology

acceptable) non-water quality environmental impacts. Because the proposed zero pollutant discharge requirement is current practice and, therefore, clearly both available and achievable, any option that includes non-zero discharge requirements for any pollutants would potentially increase pollutant discharges from current industry best practices. Such an option would not fulfill the CWA requirement to establish limitations based on “Best Available Technology Economically Achievable” (CWA section 301(b)(2)(A)), or the CWA goals of eliminating the discharge of pollutants into navigable waters (CWA section 101(a)(1)).

Third, EPA does not have any data to demonstrate that UIC capacity nationwide will be expended and that this current management approach will not be available in the future (DCN SGE00613). In fact, industry has been managing oil and gas extraction wastewater through underground injection for decades. In recent years, industry has greatly expanded its knowledge about the ability to re-use UOG flowback and long-term produced water (the major contributors to UOG extraction wastewater by volume) in fracturing another well. Consequently, while the UOG industry continues to grow and new wells are being fractured, the need for UIC capacity for UOG extraction wastewater is decreasing, even in geographic locations with an abundance of UIC capacity (see TDD Chapter D.2).

Fourth, EPA identified technologies that currently exist to treat dissolved pollutants in UOG extraction wastewater. Relative to underground injection and reuse/recycling to fracture another well (the basis for the preferred option EPA proposes), these technologies are costly, would result in more pollutant discharges, and are energy intensive. While EPA did not attempt to calculate a numerical standard for TDS, data collected for this proposed rulemaking demonstrate that the current technologies are capable of reducing TDS (and other dissolved pollutants) well below 500 mg/L. To the extent that these technologies or others are developed in the future to reduce pollutants in UOG extraction wastewater to enable them to be reused for purposes other than fracturing another well, these pre-treated wastewaters can be used directly for the other applications without going through a POTW.

Looking at each of these reasons separately demonstrates that EPA has not made a plausible argument for failing to develop a numerical standard.

First, while EPA indicates that it “...generally establishes requirements for direct and indirect discharges so that the wastewater receives comparable treatment prior to discharge to waters of the U.S.”, it should recognize that relying on a 39 year old ELG as a basis for action raises a strong signal that a more analytical

approach is necessary. Similarly, if the Agency's decision to imbed its pretreatment ELG in the Onshore Subcategory becomes a barrier to making a more thoughtful approach to define a numerical standard because of this general comparability framework, EPA should create a new Subcategory that would allow for a result that reflects the future more than the past.

Second, while UIC Class II wells are clearly an effective management option for UOG extraction waste waters, injection is not a treatment technology. Rather than assume the availability of UIC as the only technology to be used by the industry to manage its waste water – a decision that relies on unsubstantiated determinations of its widespread future availability – EPA should define a numerical, technology based BATEA for managing UOG extraction waste waters. Once the BATEA is determined, the issue of whether it is more cost effective than UIC will be a determination by the discharger. But, for those instances where UIC is not readily available – such as the circumstances that drove Pennsylvania producers to use POTWs – there would be an alternative that EPA has determined meets the technology standards of the CWA.

Third, EPA's action hinges on its assumptions that UIC capacity will continue to be a viable and cost effective option for all UOG extraction waste waters. Yet, its supporting material for this conclusion is thinly substantiated. One of its cited documents – DCN SGE00613 – is a Meeting Summary from a February 2013 meeting with industry representatives. IPAA was a participant in the meeting. EPA deduces from this document that “EPA does not have any data to demonstrate that UIC capacity nationwide will be expended and that this current management approach will not be available in the future.” This meeting never delved into a deep discussion that would yield such a conclusion; it was a general briefing to describe the nature of oil and gas extraction, the technologies that manage waste water for disposal or reuse, and the cost effectiveness of various waste water treatment to manage TDS. The text of the document states:

There is no widespread discussion in the industry about lack of injection for disposal capacity but one area that tends to have lower capacity is the Marcellus region. This is because the states of Pennsylvania and West Virginia require produced water be disposed of in the zone from which it was removed or deeper. Because of its depth, disposal into zones deeper than the Marcellus shale is not feasible.

If anything, this document emphasizes the limitations in certain regions regarding the availability of injection wells. But, it is clearly not a robust assessment of future UIC capacity. EPA also references issues regarding future UIC capacity based on a second document – TDD Chapter D.2<sup>3</sup> – by stating:

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<sup>3</sup> Technical Development Document for Proposed Effluent Limitations Guidelines and Standards for Oil and Gas Extraction, EPA-821-R-15-003, March 2015

Consequently, while the UOG industry continues to grow and new wells are being fractured, the need for UIC capacity for UOG extraction wastewater is decreasing, even in geographic locations with an abundance of UIC capacity.

However, this document does not assess future capacity issues; it merely reports on the current number of Class II disposal wells.

Industry sees a different and much less certain picture of future UIC capacity.

- One, as EPA reports, but later ignores, there are some areas where UOG extraction is intense – such as the Marcellus Shale – where UIC capacity does not exist.
- Two, because UOG extraction well waste water cannot be reinjected for oil or gas recovery, this waste water must be sent to UIC disposal wells or managed. As a result, there will be pressure to expand existing disposal wells or drill new ones.
- Three, EPA discounts this pressure by emphasizing waste water recycling/reuse. Recycling and reuse are viable and valuable but they are not a panacea. Real limits on recycling/reuse include the pace of new well development, the proximity of new wells to the waste water, the adequacy of water volumes in a specific area and the contaminant levels in the water. Moreover, as certain fields become more production-focused, as opposed to having aggressive active exploration, there are greater needs to manage produced water and even fewer opportunities to recycle/reuse it for fracturing operations. As such, recycling/reuse activities are not only driven by the intensity of drilling activities in a certain resource play but by its stage of development. As time progresses, the Marcellus Shale, for example, will experience an even greater need for disposal options.
- Four, in the time period that EPA has been developing this ELG proposal, the regulatory framework for Class II UIC wells has been subjected to new challenges, particularly for disposal wells. As environmental fossil energy/fracturing opponents have failed to show that state regulated fracturing presents unmanageable environmental risks, they have turned to other elements of unconventional oil and gas production. One of these is UIC disposal. Over the past several years issues related to triggered seismicity have been imputed to UIC disposal wells. These allegations threaten new well permits and existing operations whether caused by technical regulatory constraints or local opposition. Similarly, EPA initiated a review of the process that states use to exempt aquifers from regulation under the SDWA. Aquifers related to oil and gas extraction have historically been excluded from the SDWA scope but if changes are made to areas that are possible disposal sites, future UIC options could be diminished. Primacy delegation under the SDWA is being challenged. Efforts are active to stir up opposition to waste water movement from one state to another. Collectively, these challenges to

UIC Class II disposal options can limit future capacity at a time when assumptions about reuse must be cautious not ebullient.

Consequently, EPA’s reliance on the past success of UIC to serve as the basis for a zero discharge ELG is misplaced.

Fourth, EPA too readily dismisses treatment technologies as “...costly, would result in more pollutant discharges, and are energy intensive” compared to UIC or reuse. These technologies may be more costly and result in pollutant discharges. However, the CWA does not demand that BATEA be inexpensive and discharge free. It requires that the technology be what the description says – the best available technology economically achievable. It is EPA reliance on a non-CWA management technology – injection wells under the SDWA – that brings about that comparison. And, as stated above, EPA reaches the conclusion to rely on Class II UIC disposal wells too cavalierly.

Instead, EPA needs to fully assess a variety of technologies – most of which have been developed as a part of the industry recycling and reuse initiatives – to determine their capacity to manage waste water in the context of pretreatment. These technologies might include sedimentation, filtration, chemical precipitation, dissolved air flotation, biological treatment, reverse osmosis (RO), forward osmosis (FO), evaporation (no recovery), evaporation with condensation, membrane distillation, and crystallization. Certainly, these technologies produce different outcomes and are appropriate for different waste waters. Their costs and their effectiveness will differ. But, until EPA evaluates them, no one knows which may constitute BATEA for pretreatment. For example, the following table presents some framework of technologies that might be considered for recycling and reuse. They may bear on a BATEA analysis as well, but EPA needs to make the analysis necessary for such a determination.

Treatment Technology	Max TDS Recommended for Treatment (ppm)	Relative Cost	Commercially Available
Reverse Osmosis Membrane	50,000	\$	Yes
Forward Osmosis Membrane	100,000	\$\$	No
Evaporation*	200,000	\$\$	Yes
Membrane Distillation	280,000	\$\$	No
Crystallization	500,000 +	\$\$\$\$	Yes

While EPA may raise questions about whether they are too costly compared to other options, ultimately, it is the producer that will have to make an economic decision among the various options available. By making no BATEA analysis of technology options, EPA prevents that decision from being considered.



EPA needs to reconsider the UOG extraction facilities pretreatment ELG and determine appropriate BATEA for actual unconventional oil and natural gas development.

#### *Small Business Implications*

Taken together, EPA's action to cover conventional oil and natural gas production and to prohibit the discharge of conventional produced water to POTWs in addition to its prohibition of direct discharges of produced water can fall most heavily on small business operators. State permitting agencies have the responsibility to protect their waters – and they do so effectively. Even without an ELG, state permit writers must determine whether a discharge option is appropriate and to define technology options using Best Professional Judgement (BPJ) decisions under the CWA. If a state has determined that it can meet its water management responsibilities and allow conventional oil and natural gas produced water to be managed in POTWs, EPA should not preclude it, particularly if that option is essential to small businesses.

#### *Recommendations*

EPA needs to reconsider at least the 2016 ELG for onshore UOG extraction facilities POTWs. EPA's absolute failure to develop technology based BATEA requirements undermines the fundamental premise of the CWA and sets a precedent for all future oil and natural gas production ELG decisions that now rely on decisions made in 1979 regarding a vastly different industry.

### **SOLID WASTE REGULATIONS**

The Resource Conservation and Recovery Act (RCRA) defines the federal management structure for hazardous (Subtitle C) and nonhazardous (Subtitle D) solid wastes. Oil and natural gas production operations produce wastes that must be managed as solid wastes, primarily drilling fluids and produced waters at production sites. Ultimately, produced water is regulated under the federal CWA or Safe Drinking Water Act (SDWA). In 1980, Congress concluded that state regulatory programs managing oil and natural gas production wastes were designed to apply to those wastes and that Subtitle C was not an appropriate option. In 1988, EPA completed a Congressionally mandated Regulatory Determination concluding that:

- RCRA Subtitle C was not appropriate for oil and natural gas production wastes;
- State programs were effectively managing these wastes; and,
- Applying RCRA Subtitle C to production wastes would significantly and adversely affect American oil and natural gas production.

Since that decision, Keep It in the Ground environmental advocates have repeatedly sought to subject oil and natural gas production wastes to federal requirements knowing that it would result in devastating consequences for American production.

Recently, these groups turned their attention to Subtitle D and extracted a consent decree from EPA to determine if it needs to develop federal regulations under Subtitle D.

EPA has a long history working with states since its 1988 Regulatory Determination. Some of this activity has been formal such as the state review programs initiated after the Regulatory Determination and currently conducted through the STRONGER (State Review of Oil and Natural Gas Environmental Regulations) process. Other actions have been informal working

with individual states, with the Interstate Oil and Gas Compact Commission (IOGCC) and with the Ground Water Protection Council (GWPC). Given these ongoing interactions with state programs, EPA clearly understands the effectiveness of these programs.

Subtitle D frames very general authority for EPA. However, there are some provisions that were used by the environmental groups to trigger the litigation leading to the consent decree. These are:

**40 CFR, Part 257 – Criteria for Classification of Solid Waste Disposal Facilities and Practices** - establishes regulatory standards to satisfy the minimum national performance criteria for sanitary landfills. These criteria established standards for determining whether solid waste disposal facilities and practices may pose adverse effects on human health and the environment. Facilities that fail to meet the criteria are "illegal dumps" for purposes of state solid waste management planning efforts under Subtitle D. *The criteria provide the basis for enforcing the prohibition on "open dumps" and may be used by citizens' suits in Federal District Court.*

**40 CFR, Part 256 – Guidelines for Development and Implementation of State Solid Waste Management Plans** – establish the elements that state solid waste management plans must contain to qualify under RCRA Subtitle D.

EPA has rarely utilized its authority under these sections of RCRA. However, each of these sections include requirements used by the environmental groups arguing that EPA must review its Subtitle D programs every 3 years and determine whether it needs to develop federal regulations and state guidelines or if the current programs, including state regulations, are adequate.

Now, under the consent decree, EPA must determine whether to act under these sections by March 2019. EPA can determine that state programs are – as they clearly have been – effective in managing production wastes and no action is needed under Subtitle D. Or, EPA can propose a Subtitle D federal program. Given the unique nature of these wastes, neither Subtitle C nor Subtitle D provide a framework for a production wastes regulatory structure – particularly a national regulation that could not reflect the different environments of the oil and natural gas producing states. Moreover, Subtitle D does not compel states to adopt federal regulations. With regard to production wastes, the clear history of successful, well managed state regulations means that states would not choose to sacrifice their programs for an untried federal one.

However, if EPA created Subtitle D regulations, that action would expose independent producers to litigation by environmental agitators. Under RCRA, citizen suits can be directed at individual operators that fail to comply with federal regulations. Consequently, a producer complying with state regulations that do not adopt the federal requirements would be exposed. Clearly, this is an objective of Keep It in the Ground environmentalists that use litigation as a tool to stop production, as recent efforts to use RCRA to litigate against producers regarding underground injection alleged to induce seismic events demonstrates. While that initiative was rejected in federal courts, it demonstrates the strategy that would arise if EPA writes Subtitle D federal regulations.

### *Small Business Implications*

Small business operators are a risk if EPA were to develop unnecessary federal Subtitle D regulations. They would be convenient targets for Keep It in the Ground environmentalists to attack with citizen suits knowing that the litigation costs would severely tax small business resources.

### *Recommendations*

EPA should act in 2017 to publish a determination that it does need to develop oil and natural gas production waste regulations under Subtitle D. An early action would demonstrate that the historic federal-state relationship on managing production wastes remains strong.

## **SAFE DRINKING WATER ACT**

### **Exempted Aquifers**

On March 23, 2016, the Natural Resources Defense Council (NRDC) filed a petition with EPA under the Administrative Procedure Act (APA) seeking changes to the aquifer exemption (AE) program under the SDWA.

Among other things the petition demands that EPA:

1. Impose a moratorium on all AE related decisions including granting new exemptions or expanding the boundaries of existing exempt areas.
2. Update the regulations and criteria for designating exempt aquifers through a formal rulemaking process.
3. Eliminate criteria that allow aquifers to be exempted when hydrocarbons are demonstrated to be naturally occurring in the groundwater.
4. Consider increasing the threshold for Underground Source of Drinking Water (USDW) protection from 10,000 mg/L TDS to as high as 40,000 mg/L TDS.
5. Revisit all previously issued exemptions to determine if the exemptions should be rescinded based on the new criteria.

The NRDC asserts that new information has arisen since the aquifer rules were written, and that EPA must update its rules to account for increasing groundwater demand, climate change, and technological advancements for brackish groundwater desalination.

Class II injection wells are essential to oil and natural gas production. Primary uses of injection wells include the injection of water, steam, and CO<sub>2</sub> to conduct enhanced oil recovery (EOR) and water disposal associated with oil and natural gas production in areas where no other disposal options are available. Without the ability to utilize Class II injection wells, American oil and natural gas production in many areas of the country would be dramatically curtailed or shut in altogether.

Under the SDWA, Class II injection activity is allowed in areas where the groundwater quality exceeds the USDW threshold of 10,000 TDS mg/L. Injection where the groundwater contains less than 10,000 TDS mg/L is only allowed in areas that have been formally exempted pursuant to a state application that has been submitted to EPA. EPA maintains general criteria that an application must demonstrate in order to qualify for an exemption, not the least of which is that

the area proposed for exemption does not supply drinking water, and cannot feasibly be expected to economically provide drinking water. The existing criteria require extensive geologic and water quality information to be submitted in order to gain approval and provide significant flexibility to allow the state and federal agencies involved in the review to consider site specific factors that are relevant to the decision.

The proposed actions sought in the NRDC petition could potentially halt the ability of states to permit new injection wells until EPA conducts a multiyear rulemaking proceeding. Development of new water disposal and EOR wells would likely be placed in limbo while EPA reviews the status of areas that have been exempt for more than thirty years and considers whether to revise the definition of a USDW. State regulatory agencies in areas where the groundwater exceeds 10,000 mg/L TDS could prospectively be forced to spend considerable resources preparing applications to go through the federal exemption process as a condition of maintaining operations they had already permitted and were actively regulating.

In California, the third largest producing area in the country, EPA Region 9 directed the California Division of Oil, Gas & Geothermal Resources (DOGGR) in 2010 to update the exemption boundaries for more than 50 oil fields throughout the state. More than 25 applications have already been prepared using the current approved criteria and are being submitted to EPA for review. New drilling in many areas of the state has been put on hold for the past several years while the scientific based applications have been under development. Approval of the NRDC petition would essentially nullify the significant resources that have been expended in an effort to comply with EPA's directive and would extend the drilling moratorium in perpetuity.

Abrupt agency approval of the application would also likely lead to a significant reduction in drilling new production wells. Without adequate injection well capacity to handle produced water, some producers may be forced to suspend capital investments in new production wells. Many areas with oil and natural gas resources would likely be precluded from development altogether if the resources require EOR operations or the operators do not have access to reasonable methods of produced water disposal and management. Major oil and gas producing states impacted by this review include: California, Utah, Colorado, Wyoming, North Dakota, Texas, Louisiana, Ohio, and Oklahoma.

The lack of confirmed impacts to groundwater from oil and natural gas related injection activities validates that the historic criteria used by EPA has served to protect areas with true groundwater supply potential. Furthermore, the existing criteria provide the state regulatory agencies significant flexibility in making decisions to protect local groundwater resources while facilitating new oil and natural gas development.

The goal of the NRDC petition is to dramatically advance the "Keep It in the Ground" agenda by imposing a multiyear moratorium on a critical type of well that is essential to supporting existing and new oil and natural gas operations.

#### *Small Business Implications*

Class II injection wells are the widely available technology to manage produced water or to use produced water for secondary recovery in conventional wells in most producing formations. Loss of access to Class II wells for small businesses would prevent the continued operation of many low producing wells.

## *Recommendations*

EPA retains considerable discretion under the APA on how quickly it must respond to petitions.

It can choose to grant approval and initiate a rulemaking proceeding, or deny the petition outright. Since there are no timing restrictions that guide EPA's response, the agency can act promptly and without significant public notice, or it can delay its response for an extended period. EPA is not required to hold a public comment period before it takes action on a petition.

EPA should act to deny the NRDC petition and continue to use the current process to determine aquifer exemptions. Additionally, EPA regions should be directed to work closely with states to facilitate their determinations.

## **STATE DELEGATION**

Major federal environmental laws hinge on an effective federal-state relationship. At the heart of this relationship is the distribution of responsibilities between the governments. When Congress created its federal environmental laws, it recognized the joint realities that most states already operated environmental regulatory programs and that the Congress would never create nor fund a competing federal program. Consequently, it turned to the approach of partnering with the states through the process of delegating federal authority to the states. As a result, the federal government's role is principally creating national standards, authorizing state management of federal law, stewarding state regulatory actions, addressing interstate and international issues and funding for research and state support. State regulators are the primary creators for the regulatory requirements that permit and managing environmental emissions and discharges.

This balance creates an effective system that is predictable. However, it functions best when each partner stays within its fundamental responsibilities. Unfortunately, for American oil and natural gas production, over the past 8 years, federal agencies aggressively acted to expand the scope of regulation to provide pathways for federal action in spite of state regulations.

This effort creates unnecessary conflict with states. States have effectively managed the environment within their borders and have crafted regulatory systems that reflect their specific circumstances. EPA cannot, through national regulations, create the flexibility necessary address these differing situations. Additionally, EPA has initiated enforcement actions that have attempted to usurp the regulatory roles of states – actions that have not been justified.

For industry, confronting different regulatory demands from states and the federal government is both costly and confusing – exposing them to possible penalties that are out of their control. Industry is prepared and committed to meeting its environmental management responsibilities, but it needs certainty and it seeks the most cost effective approach to action.

Expanded delegation of federal authority to states is the straightforward path to improve this situation. However, EPA needs to recognize that much of the delegation process was conducted decades ago when federal laws were initially passed. Consequently, EPA needs to determine if the current delegation process is still workable. State regulatory programs are different now with a mature understanding of how to effectively regulate. In the past, EPA has put limits on delegation based on its understanding of the regulatory processes at the time; these structural constraints need to be examined and revised if appropriate – actions that should be taken in conjunction with the states.

Funding is another key factor. State budgets face similar constraints faced by the federal budget. However, states will not be positioned to undertake greater delegated responsibilities without adequate funds. EPA must address this need.

#### *Small Business Implications*

By their nature, regulatory burdens are always more difficult for small businesses. In this case, the burdens of multiple state and federal permits, of state and federal regulatory compliance, of duplicative state and federal reporting need to be recognized and minimized.

#### *Recommendations*

EPA needs to expand and enhance delegation of regulatory authority to states. It needs to eliminate barriers that may exist.

The Trump Administration needs to work with Congress to assure that adequate funding is provided to states to encourage delegation.

### **ENFORCEMENT**

Without question, compliance with environmental regulations is a clear and certain responsibility of every oil and natural gas producer. Equally certain, regulators have the responsibility to assure that compliance occurs and to enforce compliance when necessary. Two challenges, then, are what entities should enforce and how should that enforcement take place.

State agencies are the primary enforcers of their regulations. However, EPA can exert its enforcement authority when it concludes that a state is not adequately managing a federally delegated program or where there is no state authority – for example, under a Federal Implementation Plan under the CAA or where the state has not been delegated authority.

From our perspective, EPA needs to thoroughly review and revise its federal enforcement process. It needs to create an enforcement program that treats the regulated community with fairness, respect and dignity. It needs to eliminate the use of excessive threatening tactics, egregious fine proposals and enforcement to compel regulation where EPA has no authority.

For example, in North Dakota EPA Enforcement initiated an aggressive action related to the storage tank component of Subpart OOOO. It targeted a private company, rather than a publicly held company. It threatened the company with fines that would exceed the company's value and possibly the entire assets of the family owners. Its basis for action relied on interpretations of the regulation that differed from those provided by EPA's technical staff. And, of course, it then used these threats not only to compel operational changes to the storage vessels, but to demand additional actions beyond the scope of the regulations. This type of egregious enforcement must be halted.

#### *Small Business Implications*

Small businesses should not be the convenient targets of the federal litigators' unlimited budgets. EPA's Enforcement Office should not target small business companies where it hopes to use its essentially unlimited power to subjugate them to meet its interpretation of regulations.

### *Recommendations*

Unfortunately, Keep It in the Ground environmentalists clamor to the press and plaster the internet with allegations that any change to scrutinize the current enforcement approach at the Agency is tantamount to an abdication of federal responsibilities. In reality, the current EPA enforcement program appears to be too loosely managed. As a result, EPA Regional Offices and each Headquarters Program office can initiate and pursue enforcement actions without any coordinated standards. EPA needs to create a consistent set of standards and expectations.

Any federal agency can unleash an abusive enforcement program and justify it as necessary to make sure the regulated community is held accountable. But, the regulated community is overwhelming committed to complying with its regulatory burden. It, after all, lives in the communities where it operates. And, it must meet its shareholders' expectations as a good corporate citizen.

EPA needs to craft an enforcement program that assures that federal laws are being properly implemented, but not one that seeks to use its authority to seek actions beyond the scope of the law. It needs to be forceful but fair and respectful. It needs to be an enforcement program that is accountable.

### **COST EFFECTIVENESS CALCULATIONS**

A key component of regulatory development involves the determination of the costs and benefits of regulations. Clearly, any such process is an open invitation for abuse. Costs can be understated; benefits can be overstated. History indicates that both have been done to produce a result that falls within whatever target has been set.

Recently, one of the regulatory arenas where obvious abuse has occurred is the development of benefits to justify climate change related regulations. The most notable area of abuse is the creation of the Social Cost of Carbon, Nitrous Oxide and Methane. The generation of these costs were cloistered and obscure. The process did not allow for the openness needed to have any confidence in its application. And, in its use, agencies were able to apply it to conveniently adjust estimates when needed. The March 28, 2017, Executive Order eliminating Social Cost use was entirely appropriate to bring certainty and confidence to the regulatory review process.

Yet, other calculations – less visible, less obviously manipulated – were similarly abused in regulatory analyses. For example, in the justification for Subpart OOOOa, EPA based its recovered methane basis and its economic evaluations on natural gas prices that were wholly inaccurate. Specifically, EPA used a methane value of \$4.00/mcf. For a producer to receive \$4.00/mcf for its gas sales, the market price would have to be about \$5.33/mcf to account for royalties and fees. Currently, natural gas prices are ranging around \$3.00/mcf, meaning that the producer would be getting about \$2.25/mcf. This significant overestimate of the value of natural gas roughly doubles the benefits of methane regulations without the imposition of Social Cost benefits. EPA never brought its cost effectiveness calculations into the realistic framework of actual natural gas prices.

### *Recommendations*

As EPA reconsiders regulation of oil and natural gas production facilities, it needs to fully recognize that the economic calculations regarding cost effectiveness should be revised.

## CONCLUSION

These issues are examples of issues that directly affect independent producers from EPA regulations and potential regulations. The fundamental problem, however, is EPA's failure to do the work to understand American oil and natural gas production. A former EPA Administrator was reported as stating:

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.

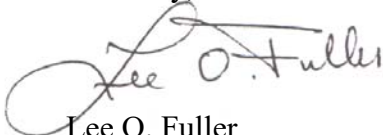
Unfortunately, EPA has been regulating before it has learned. Unlike most industries, oil and natural gas production begins to decline soon after it starts. The industry is comprised of large and small businesses with most low producing wells operated by small businesses. Regulations that might be cost effective when a well is new will not be after it declines and certainly when it is a low producing well. Imposing regulations designed for new sources on existing sources will almost certainly threaten their existence.

EPA has the authority to subcategorize its regulatory actions. For example, it has the capacity to distinguish between large and small sources – or to exclude small sources altogether – or to delay regulation of small sources until it has the information to understand how to develop small source cost effective regulations. But, it has chosen not to utilize this flexibility – at least in its recent actions.

EPA needs to recast its thinking. It needs to develop the understanding of the industry that it does not have.

IPAA appreciates the opportunity to submit these comments. If additional information is needed, please contact Lee Fuller at [lfuller@ipaa.org](mailto:lfuller@ipaa.org) or 202-857-4722.

Sincerely,

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

Lee O. Fuller  
Executive Vice President



## APPENDIX 1

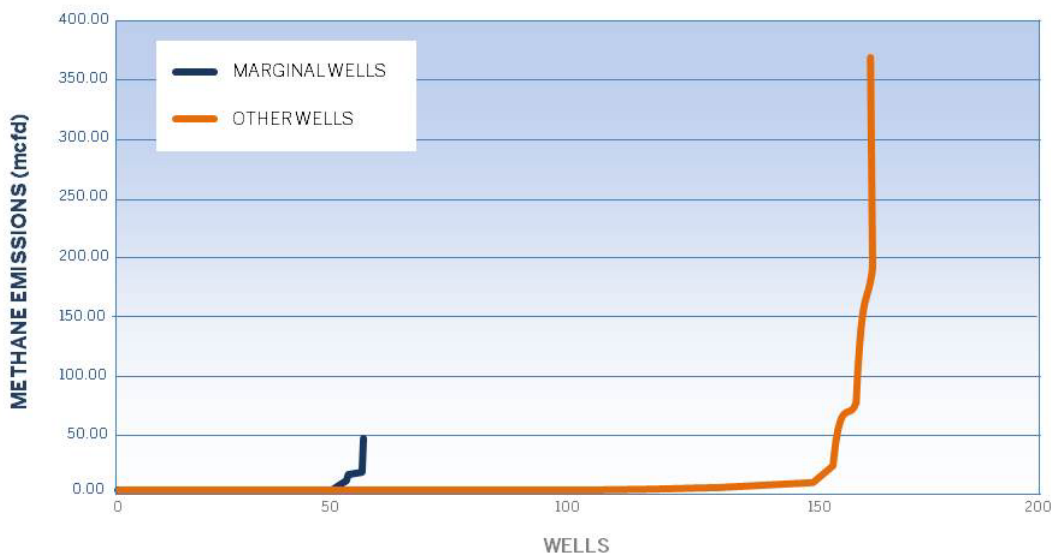
### Manipulating Data to Create the Illusion That Low Producing Wells Are “Super-Emitters”

This document addresses data manipulation issues in the environmentalist study submitted to the rulemaking proposal for Subpart OOOOa to distort the role of low producing wells regarding methane emissions. This study was then characterized as the basis for removing the low producing well exclusion for the Subpart OOOOa fugitive emissions program initially proposed by the Environmental Protection Agency (EPA).

#### Background

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

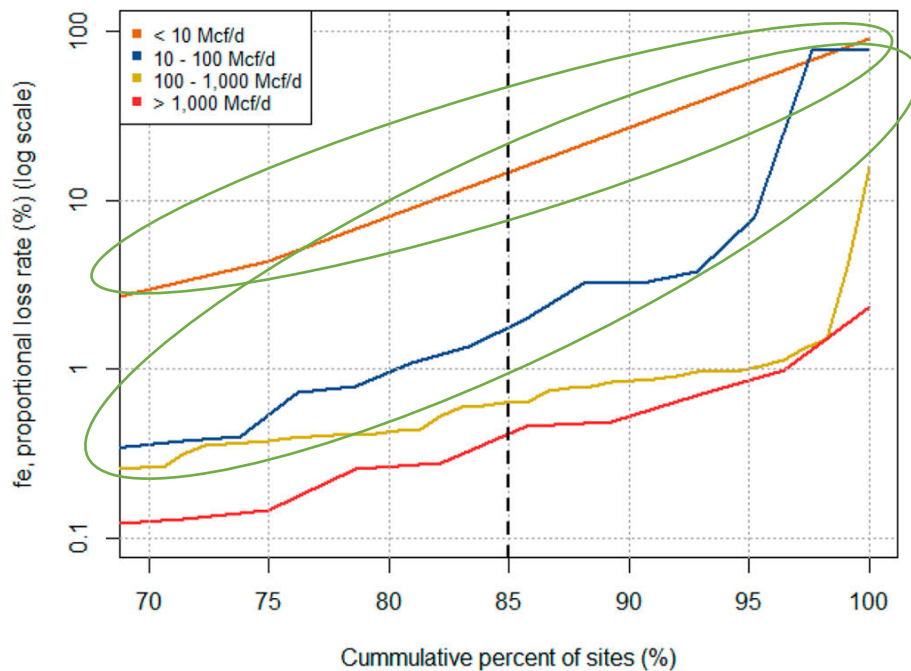
Before turning further to describe the submitted study, it is useful to look at the same data using a direct graph of emissions. In this graph, marginal wells are those with production volumes of 90 mcf/d or less.



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

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

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



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

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

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

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

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

These observations can be made without conducting an intense investigation of the study. They are obviously intended to contort data to create a specific result. Yet, with all the investigative power at EPA, with all of the research work EPA has conducted, EPA took this contrived study at face value to make its determination to remove the low producing well exclusion in the Subpart OOOOa regulations. That decision – particularly void of any opportunity for public review – should not be allowed to stand.